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Exhibit 99.1

Exhibit
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Disclaimer

FORWARD-LOOKING STATEMENTS

The information in this presentation and the oral statements made in connection therewith include "forward-looking statements" within the meaning of Section 27A of the Securities Act and Section 21E of the Securities Exchange Act of 1934, as amended. All statements, other than statements of present or historical fact included in this presentation, regarding Silver Run II's proposed business combination with Alta Mesa Holdings, LP ("Alta Mesa") and Kingfisher Midstream, LLC ("KFM"), Silver Run II's ability to consummate the business combination, the benefits of the business combination and Silver Run II's future financial performance following the business combination, as well as Alta Mesa's and KFM's strategy, future operations, financial position, estimated revenues and losses, projected costs, prospects, plans and objectives of management are forward-looking statements. When used in this presentation, including any oral statements made in connection therewith, the words "could," "should," "will," "may," "believe," "anticipate," "intend," "estimate," "expect," "project," the negative of such terms and other similar expressions are intended to identify forward-looking statements, although not all forward-looking statements contain such identifying words. These forward-looking statements are based on management's current expectations and assumptions about future events and are based on currently available information as to the outcome and timing of future events. Except as otherwise required by applicable law, Silver Run II, Alta Mesa and KFM disclaim any duty to update any forward-looking statements, all of which are expressly qualified by the statements in this section, to reflect events or circumstances after the date of this presentation. Silver Run II cautions you that these forward-looking statements are subject to all of the risks and uncertainties, most of which are difficult to predict and many of which are beyond the control of Silver Run II, Alta Mesa and KFM, incident to the development, production, gathering and sale of oil, natural gas and natural gas liquids. These risks include, but are not limited to, commodity price volatility, low prices for oil and/or natural gas, global economic conditions, inflation, increased operating costs, lack of availability of drilling and production equipment, supplies, services and qualified personnel, processing volumes and pipeline throughput, uncertainties related to new technologies, geographical concentration of Alta Mesa's and KFM's operations, environmental risks, weather risks, security risks, drilling and other operating risks, regulatory changes, the uncertainty inherent in estimating oil and natural gas reserves and in projecting future rates of production, reductions in cash flow, lack of access to capital, Alta Mesa's and KFM's ability to satisfy future cash obligations, restrictions in existing or future debt agreements of Alta Mesa or KFM, the timing of development expenditures, managing Alta Mesa's and KFM's growth and integration of acquisitions, failure to realize expected value creation from property acquisitions, title defects and limited control over non-operated properties. Should one or more of the risks or uncertainties described in this presentation and the oral statements made in connection therewith occur, or should underlying assumptions prove incorrect, Silver Run II's, Alta Mesa's and KFM's actual results and plans could differ materially from those expressed in any forward-looking statements.

RESERVE INFORMATION

Reserve engineering is a process of estimating underground accumulations of hydrocarbons that cannot be measured in an exact way. The accuracy of any reserve estimate depends on the quality of available data, the interpretation of such data and price and cost assumptions made by reserve engineers. In addition, the results of drilling, testing and production activities may justify revisions of estimates that were made previously. If significant, such revisions could impact Alta Mesa's strategy and change the schedule of any further production and development drilling. Accordingly, reserve estimates may differ significantly from the quantities of oil and natural gas that are ultimately recovered. Estimated Ultimate Recoveries, or "EURs," refers to estimates of the sum of total gross remaining proved reserves per well as of a given date and cumulative production prior to such given date for developed wells. These quantities do not necessarily constitute or represent reserves as defined by the Securities and Exchange Commission (the "SEC") and are not intended to be representative of anticipated future well results of all wells drilled on Alta Mesa's STACK acreage.

USE OF PROJECTIONS

This presentation contains projections for Alta Mesa and KFM, including with respect to their EBITDA, net debt to EBITDA ratio and capital budget, as well as Alta Mesa's production and KFM's volumes, for the fiscal years 2017, 2018 and 2019. Neither Silver Run II's nor Alta Mesa's and KFM's independent auditors or Alta Mesa's independent petroleum engineering firm have audited, reviewed, compiled, or performed any procedures with respect to the projections for the purpose of their inclusion in this presentation, and accordingly, none of them expressed an opinion or provided any other form of assurance with respect thereto for the purpose of this presentation. These projections are for illustrative purposes only and should not be relied upon as being necessarily indicative of future results.

In this presentation, certain of the above-mentioned projected information has been repeated (in each case, with an indication that the information is subject to the qualifications presented herein), for purposes of providing comparisons with historical data. The assumptions and estimates underlying the projected information are inherently uncertain and are subject to a wide variety of significant business, economic and competitive risks and uncertainties that could cause actual results to differ materially from those contained in the projected information. Even if our assumptions and estimates are correct, projections are inherently uncertain due to a number of factors outside our control. Accordingly, there can be no assurance that the projected results are indicative of the future performance of Silver Run II, Alta Mesa or KFM or the combined company after completion of any business combination or that actual results will not differ materially from those presented in the projected information. Inclusion of the projected information in this presentation should not be regarded as a representation by any person that the results contained in the projected information will be achieved.

USE OF NON-GAAP FINANCIAL MEASURES

This presentation includes non-GAAP financial measures, including EBITDA and Adjusted EBITDAX of Alta Mesa. Please refer to the Appendix for a reconciliation of Adjusted EBITDAX to net (loss) income, the most comparable GAAP measure. Silver Run II, Alta Mesa and KFM believe EBITDA and Adjusted EBITDAX are useful because they allow Silver Run II, Alta Mesa and KFM to more effectively evaluate their operating performance and compare the results of their operations from period to period and against their peers without regard to financing methods or capital structure. The computations of EBITDA and Adjusted EBITDAX may not be comparable to other similarly titled measures of other companies. Alta Mesa excludes the items listed in the Appendix from net (loss) income in arriving at Adjusted EBITDAX because these amounts can vary substantially from company to company within its industry depending upon accounting methods and book values of assets, capital structures and the method by which the assets were acquired. Adjusted EBITDAX should not be considered as an alternative to, or more meaningful than, net income as determined in accordance with GAAP or as an indicator of Alta Mesa's operating performance or liquidity. Certain items excluded from Adjusted EBITDAX are significant components in understanding and assessing a company's financial performance, such as a company's cost of capital and tax structure, as well as the historic costs of depreciable assets, none of which are components of Adjusted EBITDAX. Alta Mesa's presentation of Adjusted EBITDAX should not be construed as an inference that its results will be unaffected by unusual or non-recurring items.

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Introduction

Silver Run II Delivering on Investment Criteria

Upstream

- ✓ Assets economic well below current oil price
- ✓ High margin core basin with low field break-evens, deep inventory
- ✓ Multiple Stacked Pays
- ✓ High-quality assets with significant unbooked resource potential
- ✓ Opportunities to improve costs through technology
- ✓ Opportunity to expand through technology and acquisitions

Midstream

- ✓ Competitively-positioned assets that benefit from strong supply/demand fundamentals
- ✓ Expansion opportunities in rapidly growing basin
- ✓ Locked-in base returns through stable fee-based contracts
- ✓ Assets with return asymmetry from incremental volumes, moderate margin exposure, and/or organic growth projects
- ✓ Synergy with existing upstream portfolio

Combined upstream and midstream company allows for significant value uplift from financial optimization

Pure Play STACK Company

Premier liquids upstream growth with value-enhancing midstream

- World class asset with attractive geology
  - Highly contiguous ~120,000 acres with substantial infrastructure in core of STACK
  - Oil-weighted resource with $25/BBL breakeven; >85% single-well rate of return
  - 4,200+[1] gross primary locations; 12,000+[1] possible through down-spacing and additional zones
- Top-tier operator with substantial in-basin expertise and highly consistent well results
  - 200+ horizontal STACK wells drilled across entirety of Kingfisher acreage maximizes confidence in type well EUR
  - Consistency and geographic breadth of well results affirms repeatability
  - Oil-weighted production in early well life maximizes near-term oil-based revenue (first month 2-stream production at 82% oil with 57% of the type well EUR oil produced in the first five years); consistent GOR profile
  - Industry-leading growth potential; 2-year expected EBITDA CAGR of 128%
  - Demonstrated ability to manage a large development program – average of 6 rigs running in 2017
  - Robust acquisition pipeline coupled with track record as an aggregator
- Highly strategic and synergistic midstream subsidiary with Kingfisher Midstream
  - Flow assurance de-risks production growth
  - Purpose built system designed to accommodate third party volumes – currently 6 contracted customers with approximately 300,000 gross dedicated acres
  - Strategic advantage supporting acquisition of new upstream assets
  - Future opportunity to monetize Kingfisher Midstream through an IPO, and fund upstream capital needs through proceeds of an IPO, drop downs, and GP / IDR distributions
- Financial strength and flexibility to execute business plan through the cycle; cash flow positive in 2019
  - Team has demonstrated the discipline to survive and grow through cyclical downturns

[1] Does not include additional resource potential or undeveloped locations on ~20,000 net acres recently acquired in Major, Blaine and Kingfisher counties in July 2017, as described in further detail on page 27 (the "Major County Acquisition").

Transaction Overview

- Jim Hackett and Riverstone raised ~$1 billion through Silver Run Acquisition Corporation II ("Silver Run II") IPO to invest in a market leading company which could generate significant potential return
- Silver Run II has agreed to merge with Alta Mesa ("Alta Mesa") and Kingfisher Midstream ("KFM"), collectively renamed as Alta Mesa Resources, Inc. ("AMR") at the closing of the contemplated transaction. The existing Silver Run II public stockholders and Riverstone will collectively hold a 49% interest in the combined Company1
- Pursuant to the contemplated transaction, the combined Company implied Firm Value ("FV") will be ~$3.8 billion at $10 per share, representing the following acquisition metrics:

	AMR	KFM	Total
FV / 2018E EBITDA	6.1x	7.3x	7.1x
FV / 2019E EBITDA	3.1	4.2	3.8

- Existing owners of Alta Mesa will roll 100% of their equity into Silver Run II; owners of KFM will retain significant equity stakes
- Riverstone and related investment vehicles will invest at least $600 million of cash[2]
- Anticipated closing of the transaction in 4Q 2017

[1] Assumes no Silver Run II public stockholders elect to have their shares of Class A common stock redeemed in connection with the closing of the transaction.
[2] Includes $400 million of shares of Class A Common Stock and warrants to be purchased from Silver Run II under the forward purchase agreement dated as of March 17, 2017. Does not include additional $200 million commitment from Riverstone under a forward purchase agreement entered into in connection with the proposed transaction.

Transaction Summary

Sources & Uses ($ MM)

Sources	
Legacy Owners' Rollover Equity	$1,993
Silver Run II Cash Investment	999[1]
Riverstone Cash Investment [2]	600
Total Sources	$3,591
Total Cash Sources	$1,599

Uses	
Legacy Owners' Rollover Equity	$1,993
Cash to KFM Owners	813
Cash to Alta Mesa Balance Sheet & Interim Capex Funding	786
Total Uses	$3,591
Total Cash Uses	$1,599

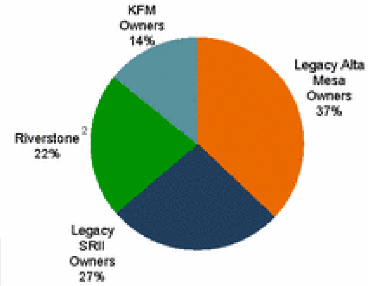
Implied Firm Value

($ millions)

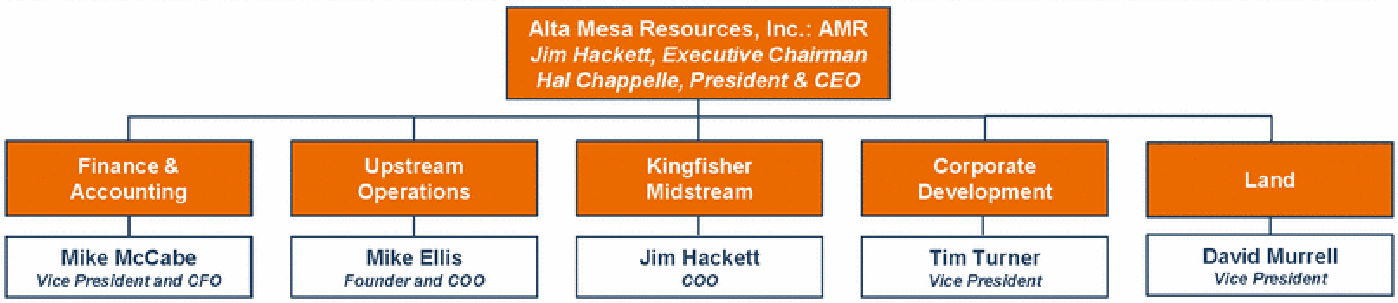
Shares Outstanding	388.6
Share Price	$10.00
Equity Value	**$3,886**
Less: Cash	(551)
Plus: Debt	500
Firm Value	**$3,836**

Transaction Multiples	
FV / 2018E EBITDA ($543)	7.1x
FV / 2019E EBITDA ($1019)	3.8x

Post-Transaction Ownership[3]



Pro Forma Organizational Structure



Note: Sources & Uses includes estimates of transaction fees, debt at close, and other transaction closing adjustments, and is subject to change.
[1] SPAC capital net of deferred underwriting expense.
[2] Reflects Riverstone and related investment vehicles, and incudes $400 million of shares of Class A Common Stock and warrants to be purchased from Silver Run II under the forward purchase agreement dated as of March 17, 2017. Does not include additional $200 million commitment from Riverstone under a forward purchase agreement entered into in connection with the proposed transaction.
[3] Assumes none of legacy Silver Run II owners exercise their stockholder redemption rights and does not give effect to any shares of Class A Common Stock that may be acquired by the Alta Mesa or KFM sellers in connection with certain earn-out provisions in the applicable contribution agreements.


Company Overview

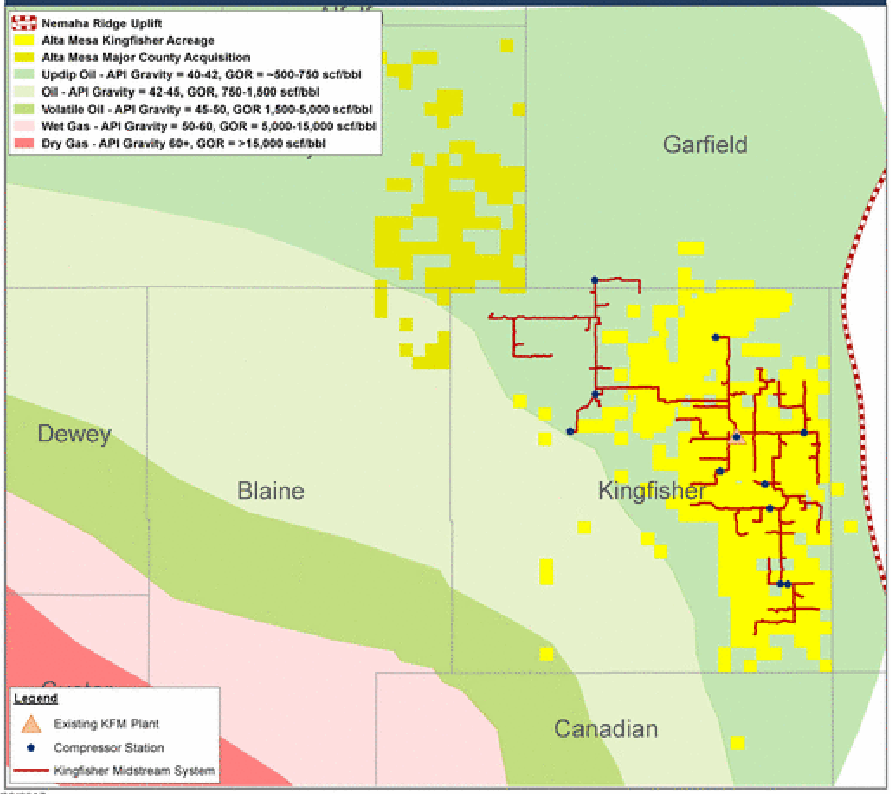
Alta Mesa Overview

Focused on development and acquisition in the STACK

Upstream Metrics	
Net STACK Surface Acres	~120,000
Current Production (BOE/D)	~20,000
% Liquids	69%
Proved Reserves (MMBOE)	144
Resource Potential (MMBOE)[1]	>1,000
Estimated Potential Gross Identified Locations[1]	4,196
Estimated Total Gross Locations[1,2]	12,133
Gross Stack Wells Producing / Horizontal Operated STACK Wells Drilled[3]	167 / 205
2017 Average Rigs	6

Midstream Metrics	
Natural Gas Processing Current / YE 2017	60 / 340[4] MMCF/D
Pipelines	300+ miles
Dedicated Acreage	~300,000 gross acres
Storage Capacity	50 MBBL with 6 loading LACTs[5]

Contiguous Core Position in STACK Oil Window



Source: Public Filings, Investor Relations.
Note: All reserve figures per NYMEX strip pricing as of 12/31/2016 close; represents acreage as of 7/20/2017.
[1] Does not include additional resource potential or undeveloped locations on ~20,000 net acres recently acquired in the Major County Acquisition.
[2] Includes additional locations from downspacing in the Oswego, Meramec, Lower and Upper Osage formations as well as additional locations in the Big Lime, Cherokee, Manning, Chester, Woodford and Hunton formations.
[3] Horizontal wells drilled as of 8/14/17
[4] Includes 80 MMCF/D offtake processing expected 3Q 2017.
[5] Lease Automatic Custody Transfer units.

High Caliber STACK Operating Team

Cohesive, tenured, scalable team producing world class results

Name	Position	Years at AMR	Years Experience
Hal Chappelle	President and CEO	13	30+
Mike Ellis	Founder and Chief Operating Officer	30	30+
Mike McCabe	VP and Chief Financial Officer	11	25+
Gene Cole	VP and Chief Technical Officer	10	25+
Kevin Bourque	VP, Mid Continent Operations	10	20+
David McClure	VP, Facilities and Midstream	7	15+
Tim Turner	VP, Corporate Planning and Reserves	4	30+
Dave Smith	VP, Geology, Geophysics & Exploration	18	30+
Ron Smith	VP and Chief Accounting Officer	10	30+
David Murrell	VP, Land	10	25+

Robust Capabilities, Organizational Scale, Public Company Processes to Drive Long-Term Success

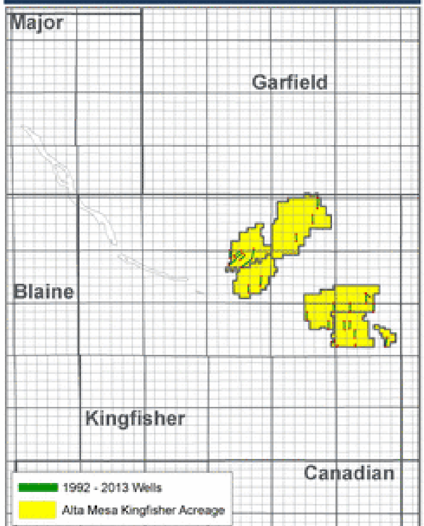
Operations (60 Employees) (40 Contractors)	Engineering & Geology (45 Employees)	Land (25 Employees)	Corporate / Finance & Accounting (50 Employees)

Relentless focus on technological advancements and continuous learning

Optimization, Delineation and Expansion

Systematic horizontal development and growth of contiguous acreage

1992 - 2013



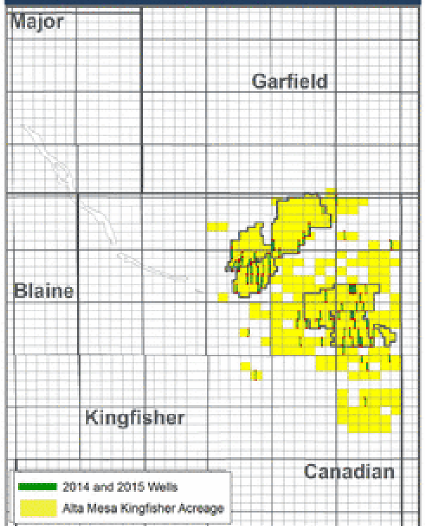
40,000+ Net Acres

1987
- Founded by Mike Ellis with ~$200K

1991
- Initial Sooner Trend acreage acquired from Conoco/Exxon/Texaco-operated units

2007-2012
- Drilled 27 vertical stratigraphic delineation wells within legacy acreage; defined robust Osage prospectivity in vertical wells
- Spud first two operated HZ STACK wells in December 2012

2014 - 2015

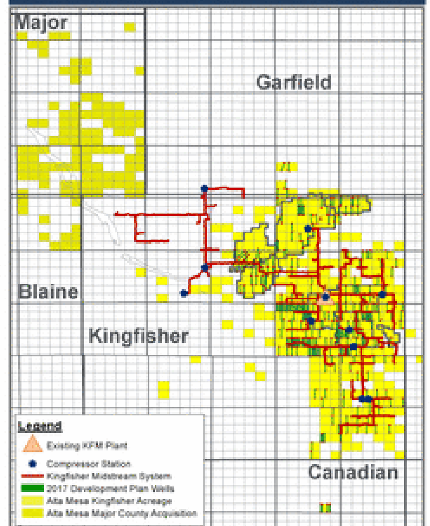


73,000+ Net Acres

2013
- Progressed through first two completion designs (Gen 1.0 and Gen 1.5)

2014-2015
- Commenced aggressive STACK leasing/acquisition and accelerated STACK development, increasing from 4 operated rigs (37% of capex budget) to 70% of total capex budget
- Built STACK acreage from 40K to 70K+ acres through bolt-on acquisitions

2016 & 2017 Plan



120,000+ Net Acres

2016
- Production reached ~20 MBOE/D
- Drilled 100th STACK HZ well & first Gen 2.5 well
- DrillCo JV started, accelerated STACK drilling with 5 operated rigs
- Phase I of Kingfisher Midstream completed, with 60 MMCF/D processing plant, crude and gas gathering, transmission pipelines, 50,000 BBL/D crude terminal, and field compression

2017
- Increased to 6 STACK operated rigs (95% of capex budget)
- Phase II of KFM expected to be complete, which includes 200MMCF/D cryo plant expansion, gas gathering pipelines, field compression and high-pressure gas transmission pipelines

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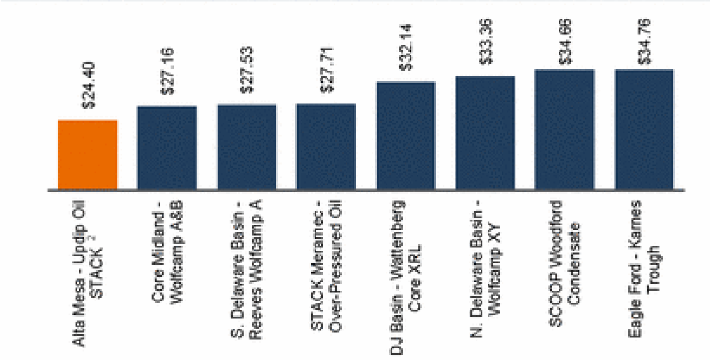
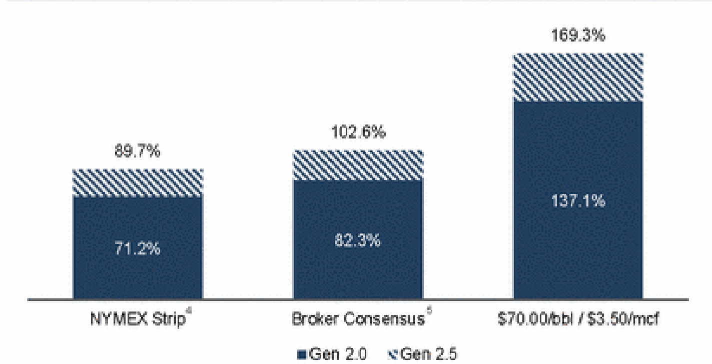
Alluring Macroeconomic Fundamentals

High quality rock drives compelling returns, robust rig activity

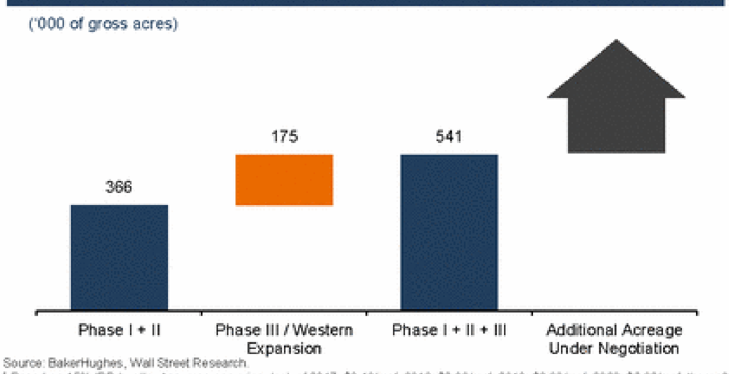
Major U.S. Oil Plays – Breakeven Prices ($/BBL)[1]



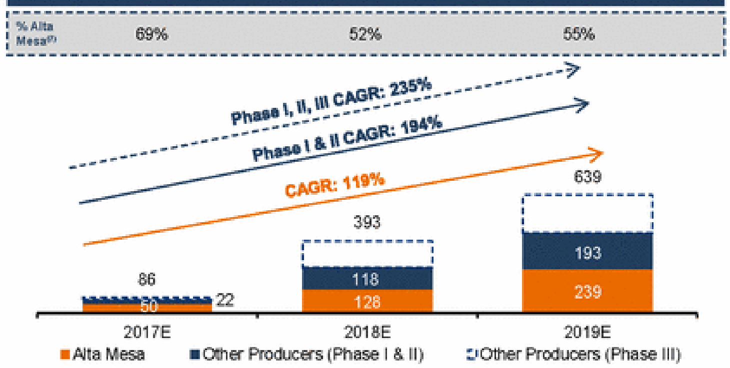
Alta Mesa Type Well IRR[3]



KFM Acreage Dedications / Resource Allocations Breakdown[6]



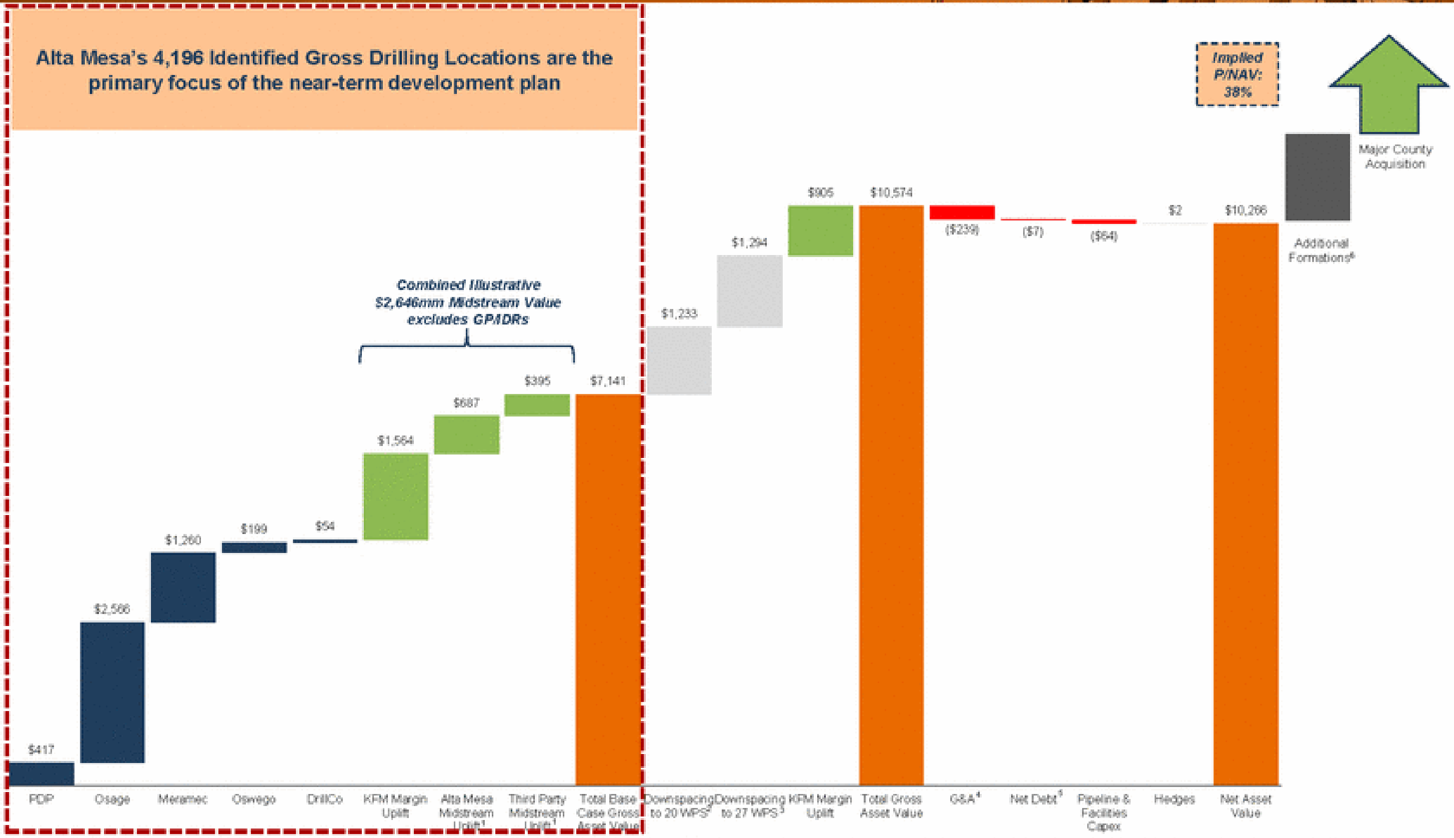
KFM Gas Inlet Volumes by Producer (MMCF/D)



Source: BakerHughes, Wall Street Research.
[1] Based on 15% IRR hurdle. Assumes gas price deck of 2017: $3.10/mcf; 2018: $2.99/mcf; 2019: $2.83/mcf; 2020: $2.82/mcf; thereafter: $2.83/mcf.
[2] AMR breakeven price company prepared. Based on AMR 651 MBOE mean type curve.
[3] Osage type curves assume 17% royalty burden and $3.2mm D&C well cost. Adjusted for transportation costs paid to KFM. Excludes $1.25 / bbl oil transportation costs.
[4] NYMEX strip pricing as of 8/3/2017 close until 2021 and held flat thereafter.
[5] Assumes Broker Consensus Price Deck (2017: $51.16/bbl / $3.16/mcf; 2018: $54.90/bbl / $3.14/mcf; 2019: $58.00/bbl / $3.05/mcf and held flat thereafter).
[6] Not inclusive of producer customers' entire gross acreage position; additional gross acreage proximate to KFM available for gathering and processing services. Includes additional acreage to come and/or under negotiation.
[7] Percentage of Phase I & II shown.

Asset Value of AMR's STACK Position

~$7B PV-10 Value from Identified Gross Locations before downspacing



Note: PV-10 figures as of 7/1/2017. Reflects Generation 2.0 Type Curve. Assumes Broker Consensus Price Deck (2017: $51.16/bbl / $3.16/mcf, 2018: $54.90/bbl / $3.14/mcf, 2019: $58.00/bbl / $3.05/mcf and held flat thereafter). Does not include additional resource potential or undeveloped locations on ~20,000 net acres recently acquired in the Major County Acquisition. Adjusted for transportation costs paid to KFM; excludes $1.25 / bbl oil transportation costs ("KFM Margin Uplift").

[1] Illustrative midstream uplift value assumes 2018E EBITDA valued at 13.7x.

[2] Low Risk downspacing of Osage to 11 WPS (966 locations), Meramec to 5 WPS (318 locations), and Oswego to 4 WPS (516 locations).

[3] Additional downspacing of Osage to 15 WPS (1,288 locations) and Meramec to 8 WPS (964 locations).

[4] Assumes 2018E Upstream G&A capitalized at 7.5x.

[5] Assumes pro forma net debt at transaction close based on Alta Mesa Q2 2017 revolver balance outstanding.

[6] Additional Formations include Big Lime, Manning, Hunton, Woodford, Cherokee, and Chester.

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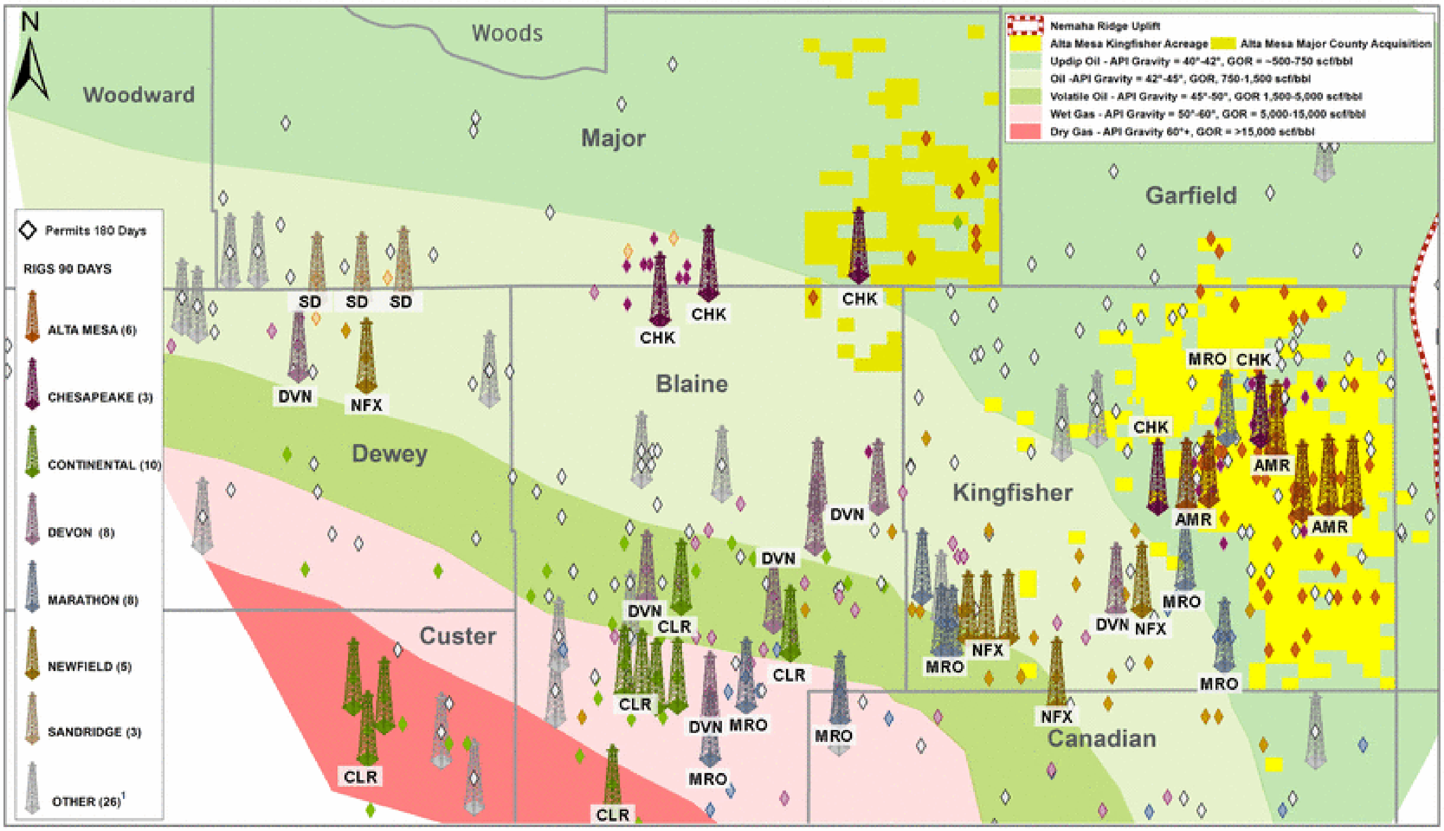
Our Upstream Assets

Significant Activity in Alta Mesa "Neighborhood"

Prominent operators active in Updip Oil Window adjoining Alta Mesa



Source: IHS Enerdeq, HPDI.
Note: Represents a combination of current and recent rig activity.
[1] Operators with 2 rigs or fewer running.

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Alta Mesa Vision

Rigorous development and balance sheet to consolidate regional assets

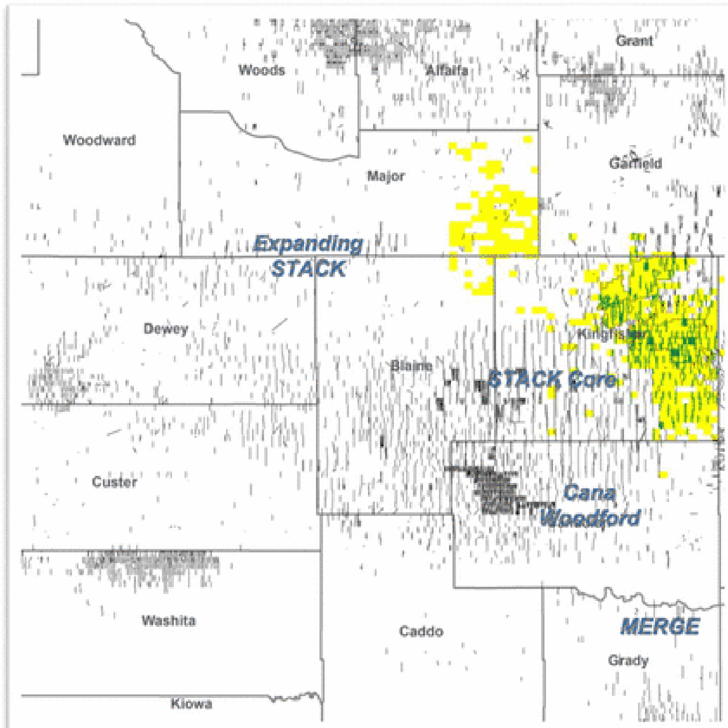
Existing Asset Value

- Early phase of systematic Meramec/Osage, and Oswego development
- Our goal: maximize discounted cash flow
  - Improve drilling efficiencies through technology and pad drilling
  - Continually optimize well density, stage spacing, pump rates, fluids, proppant, hydraulics
- Delineate and develop other horizons
  - Established productive zones – Big Lime, Manning, Cherokee sands, Woodford, Hunton
  - Untested zones – Chester Shale

STACK Enterprise Expansion

- Consolidate acreage where we can be best-in-class Operator

Alta Mesa Position in Expanding STACK/MERGE/SCOOP Area



Note: Wells drilled map as of August 2017.

Progressive Increase in Completion Intensity

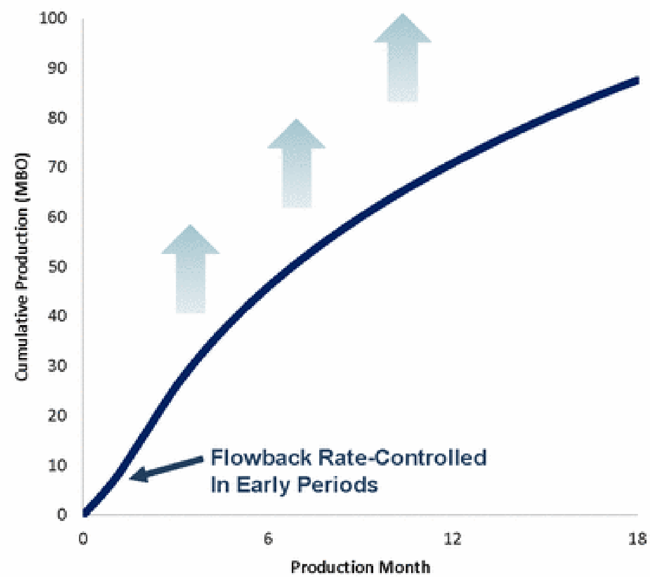
Alta Mesa leadership in operational advancements

Completion Summary By Generation

- Alta Mesa has proactively advanced completion designs with each generation – leading to improved well response and economics:
  - Number of stages increases with each generation as stage spacing decreases
  - Average sand per stage has increased with each generation
  - Total fluid per stage increases with each generation
- Continuously optimizing completions designs through reduced frac stage spacing for increased formation stimulation

Design Parameters	Gen 1.0	Gen 1.5	Gen 2.0	Gen 2.5	Current	Future
Avg Frac Stages	12	18	24	32	35	Further Improvement
Avg. Stage Spacing (Ft.)	340	256	194	150	140	
Slickwater - Avg Total (BBLS/Ft.)	29	42	56	66	75	
Sand - Total Avg. (Lbs/Ft.)	317	457	677	1,193	1,500	
Frac Design Type	Packer/Sleeve	Hybrid	Plug/Perf	Plug/Perf	Plug/Perf	
Flow Design Type	Slickwater	Slickwater	Slickwater	Slickwater	Slickwater	
Packers Type	Mechanical	Hybrid	Swell	Swell	Swell	
Well Count[1]	7	6	59	94	--	

Current Type Curve – Gen 2.0

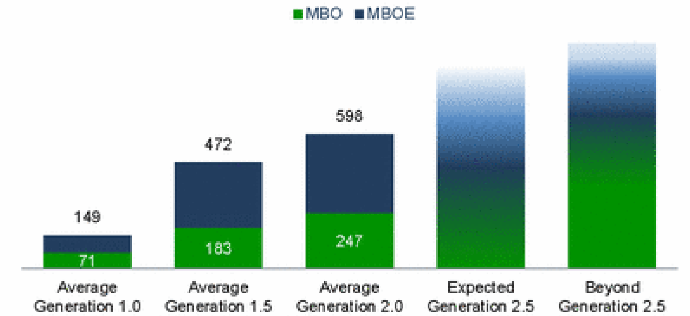


[1] Wells completed as of 8/16/17

Average Well Results

Results as of YE 2016 with early-stage Gen 2.5 forecasts

Average EUR by Generation[1]

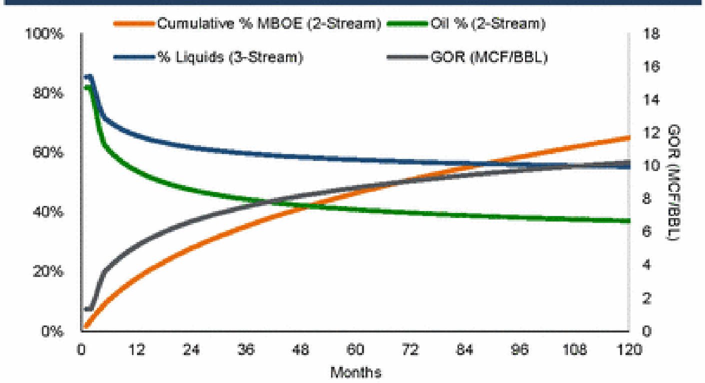


# of Wells	7	6	50		

Optimizing Stimulated Reservoir Volume

- Financial goal: maximize discounted cash flow
- Well design goal: optimize stimulated reservoir volume
  - Well spacing
  - Proppant loading
  - Fluid rates
  - Landing zones

Oil and Liquids Content Over Time[2]



Oil-Weighting Over Time

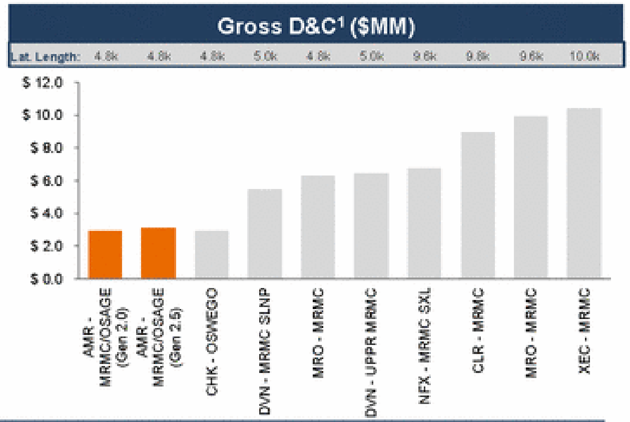
- Approximately 57% of the oil, 50% of the natural gas liquids, and 38% of the natural gas are produced in the first five years thereby enhancing the early revenue per unit and the resulting economics
- The GOR increases over time with month one approximately 1 Mcf/Bbl, month twelve approximately 5 Mcf/Bbl, month sixty approximately 8 Mcf/Bbl.
- In month one, 2-stream production from the well is 82% oil and 3-stream production is 86% liquids
- In year one, 2-stream production from the well is 66% oil and 3-stream production is 74% liquids
- The well breaches the 2-stream 50% oil point near the end of year 2 and 3-stream production remains above 50% liquids point for the life of the well

Source: Ryder Scott-audited Reserve Report, Company data.
[1] Based on Ryder Scott-audited Reserve Report. Excludes 9 wells with circumstances that will not be repeated due to unacceptable results: i) 4 wells with 660' spacing in a high porosity area, ii) 3 child wells drilled between 2 parent wells without injecting water into the parent wells prior to frac, iii) 1 well which were shut in for more than 90 days after frac, iv) 1 well that fraced into a vertical well and the vertical well was not plugged in the Osage/Meramec.
[2] LNU17N06W02A Miss well (Ryder Scott-audited Reserve Report).

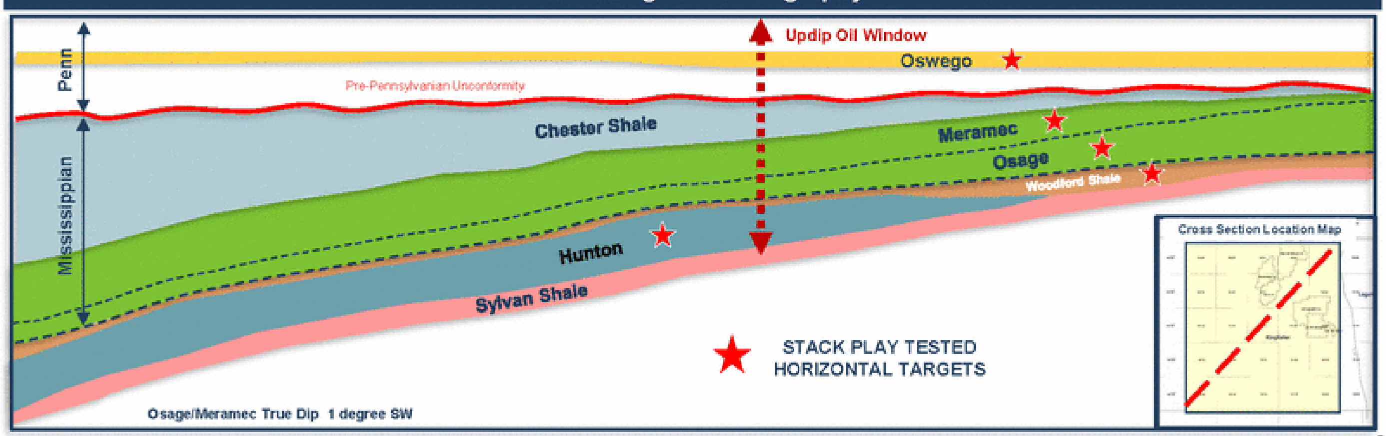
Cost-Advantaged Asset Base

Infrastructure and basic well design mitigate cost inflation

Advantage	Why It Matters
1 Shallower Targets	■ Allows for the elimination of additional strings of casing, liner tie-back, and reduces horsepower used during stimulation ■ Reduced drilling time and costs per well enhances capital flexibility and efficiencies
2 One-mile Laterals	■ Reduces mechanical risk of completions vs two-mile ■ Use less steel by utilizing smaller diameter pipe program ■ Lower cost per foot to execute drilling and completions
3 Naturally Fractured Formation	■ Heavier proppant loads not required ■ Flexibility to use more commoditized proppant



STACK Regional Stratigraphy



[1] AMR Pad Drilling D&C only and does not include $300k of allocated facilities cost.

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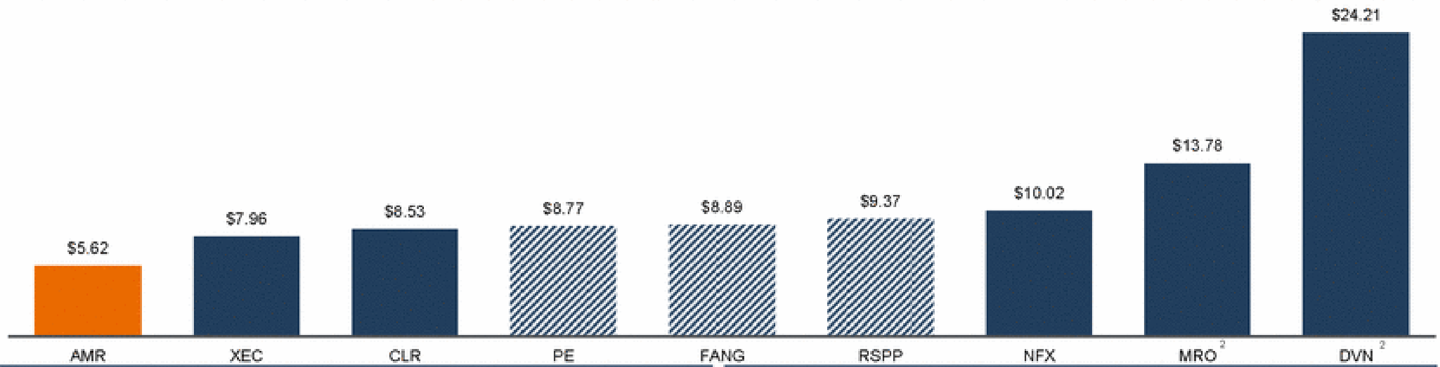
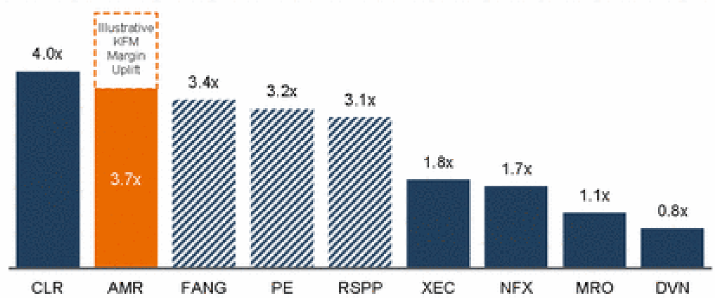
Alta Mesa: Low Cost Operator

Peer leader in operating cost and capital efficiency

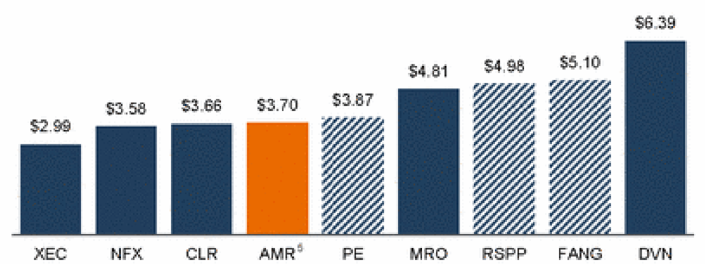
SEC Future Development Cost Per Proved Undeveloped BOE ($ / BOE)[1]



Recycle Ratio[3]



Q1 2017 LTM LOE ($ / BOE)[4]



Alta Mesa   STACK Peers   Permian Peers

Source: Public Filings as of 4Q 2016.
[1] Calculated as future development costs divided by proved undeveloped reserves. Shown as of 12/31/2016.
[2] MRO and DVN PUD F&D evaluated based on US assets only.
[3] Calculated as 4Q16 unhedged EBITDAX/BOE divided by organic F&D. Includes Q4 acquired BCE wells in calculation. Organic F&D defined as Future Development Costs / PUD volumes per SEC filings and excludes reserves added through acquisitions.
[4] Does not include gathering & transportation.
[5] LTM 3/31/2017 excluding legacy vertical and waterflood-related production.

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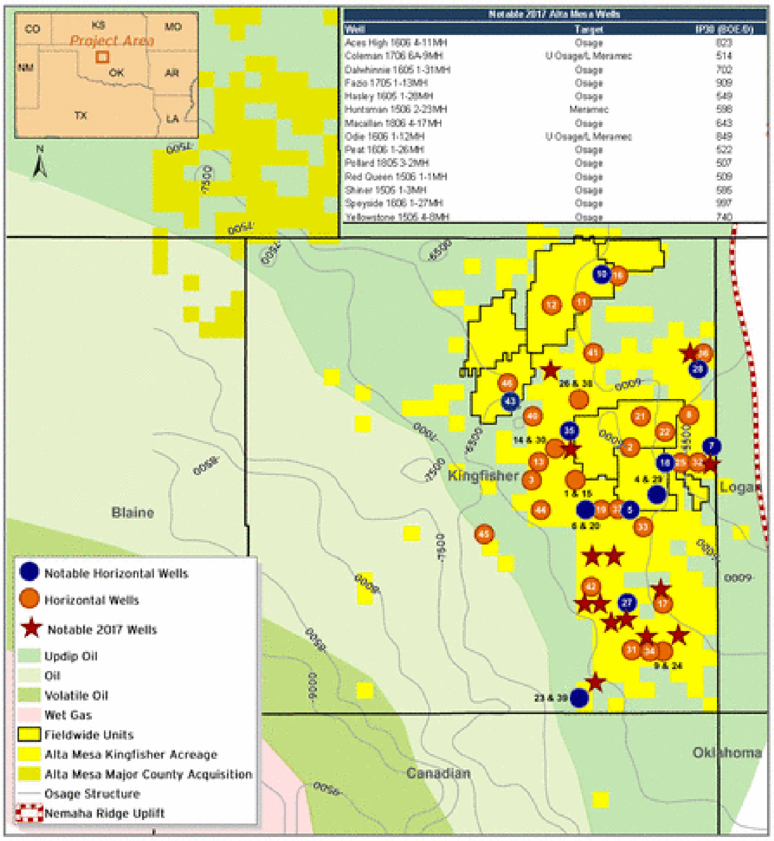
Solid Results Affirm De-Risked Acreage Position

Representative wells across 11 townships



Notable 2017 Alta Mesa Wells		
Well	**Target**	**IP30 (BOE/D)**
Aces High 1606 4-11MH	Osage	823
Coleman 1706 6A-9MH	U Osage/L Meramec	514
Dalwhinnie 1605 1-31MH	Osage	702
Fazio 1705 1-13MH	Osage	909
Hasley 1605 1-28MH	Osage	649
Huntsman 1506 2-23MH	Meramec	598
Macallan 1606 4-17MH	Osage	643
Odie 1606 1-12MH	U Osage/L Meramec	849
Peat 1606 1-26MH	Osage	522
Pollard 1605 3-2MH	Osage	507
Red Queen 1506 1-1MH	Osage	509
Shiver 1506 1-3MH	Osage	586
Speyside 1606 1-27MH	Osage	997
Yellowstone 1505 4-6MH	Osage	740

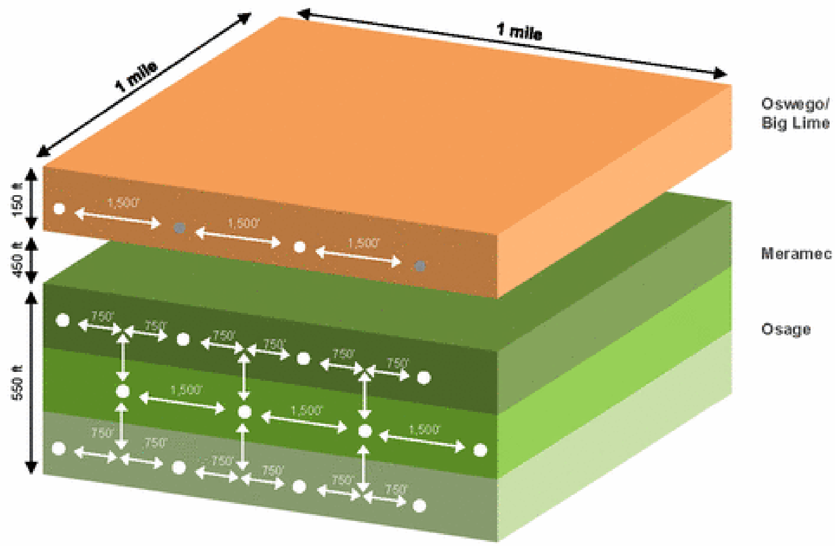
	Well Name[1]	Lateral Length	EUR (MBOE)[2]	EUR/'000 Lateral ft[2]	IP90 (BOE/D)	IP90 % Oil	IP90/'000 Lateral ft
	Operated						
1	Barbara 1708 3-22MH	4,812	579	120	348	82%	72
2	Beyer 4-6H	4,452	863	194	505	75%	113
3	Boecher 1708 4-19MH	4,832	574	119	560	72%	116
4	Bollenbach 1705 4-21MH	4,820	994	206	185	55%	38
5	Bollenbach 1705 6-30MH	4,795	1,198	250	436	92%	91
6	Brown 1708 6-27MH	4,850	839	173	316	76%	65
7	Clark 1705 5-12MH	4,657	827	178	615	85%	132
8	Cleveland 1805 2-28MH	4,645	686	148	451	77%	97
9	Dixon 1505 3-16MH	4,858	657	135	325	81%	67
10	EHU 219H	4,950	790	160	123	88%	25
11	EHU 220H	3,651	678	186	216	91%	59
12	EHU 235H	5,300	559	106	357	89%	67
13	Evelyn 1706 5-18MH	4,857	575	118	621	87%	128
14	Francis 1708 5-8MH	4,856	664	137	349	69%	72
15	Gilbert 1708 6-21MH	4,738	590	125	409	59%	86
16	Hawk 1908 7-13MH	4,813	540	112	216	80%	45
17	Helen 1605 5-33MH	4,620	652	141	331	77%	72
18	Hoskins 1705 2-9MH	4,693	932	199	507	85%	108
19	James 1708 5-26MH	4,748	738	155	352	79%	74
20	Lankard 1708 6-34MH	4,855	847	174	1,291	58%	266
21	LNU 16-2H	4,789	873	182	282	69%	59
22	LNU 49-4H	4,518	756	167	518	79%	115
23	Mad Hatter 1506 2-34MH	4,670	632	135	294	90%	63
24	Martin 1505 4-9MH	4,795	620	129	278	64%	58
25	Matheson 1705 5-10MH	4,765	729	153	449	79%	94
26	Mitchell 1808 2B-27MH	4,598	646	140	311	81%	68
27	Oak Tree 1605 2-30MH	4,744	813	171	634	69%	134
28	Oltmanns 1805 6-14MH	4,930	822	167	631	70%	128
29	Oswald 1705 6-28MH	4,815	1,144	238	278	66%	58
30	Pinehurst 1708 5-5MH	5,061	672	133	572	75%	113
31	Redbreast 1505 4-7MH	4,709	655	139	251	73%	53
32	Rigdon 17015 6-11MH	4,827	725	150	697	82%	144
33	Rudd 1605 2A-5MH	4,010	520	130	489	58%	122
34	Three Wood 1505 4-17MH	4,634	629	136	321	78%	69
35	Todd 1708 6-4MH	5,019	946	188	599	68%	119
36	Vadder 1805 2-12RMH	4,504	669	148	542	63%	120
37	Wakeman 1708 6-25MH	4,842	925	191	787	62%	162
38	Weber 1806 3-22MH	4,797	646	135	112	75%	23
39	White Rabbit 1506 2-27MH	4,811	633	132	428	91%	89
	Non-Operated						
40	Deep River 30-1MH	5,586	NA	89	324	41%	58
41	Holiday Road 2-1H	5,100	NA	67	153	85%	30
42	King Koopa 1808 2UMH-22	4,691	NA	83	380	60%	81
43	OOID 1OH-24	5,357	1,459	272	533	88%	99
44	Post 1706 1-30MH	4,919	456	93	461	66%	90
45	Ruzek 1H-3X	6,872	498	72	688	67%	100
46	Trifecta 1807 20H-14-1	4,346	662	152	555	92%	128

Source: Alta Mesa Year-End Reserve Report. For non-Alta Mesa operated wells, IHS Enerdeq.
Note: EURs based on NYMEX 2016 pricing. Does not include additional resource potential or undeveloped locations on ~20,000 net acres recently acquired in the Major County Acquisition.
[1] Includes 7 wells not operated by Alta Mesa. Includes wells operated by Chaparral, GST, MRO and NFX.
[2] 3-Stream EUR assuming 75.4 BBL/MMCF NGL yield and 15.9% shrink.

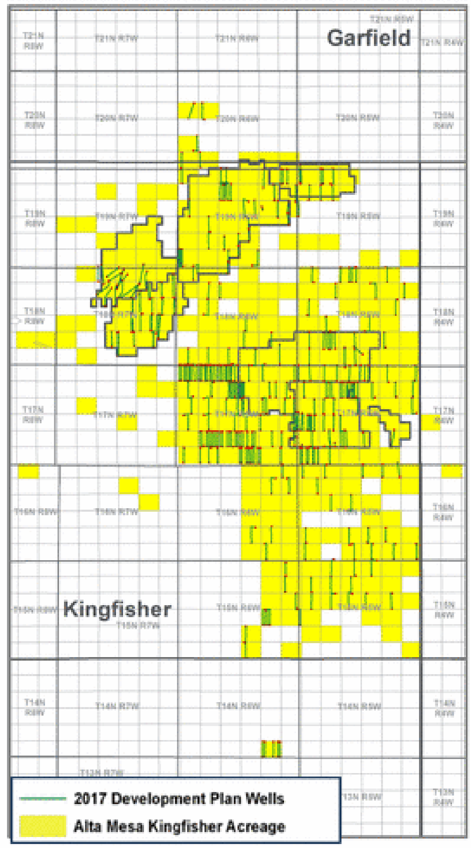
Alta Mesa STACK Development

Moving into development mode on de-risked Kingfisher acreage

Base Case Development Plan For AMR



2017 Development Plan



Alta Mesa Development Strategy

- Near term development plan focuses on continued optimization of frac stage spacing, transitioning to development mode, delineating Oswego performance, and accelerating infrastructure investments
- Delineate and de-risk recently acquired Major County Acquisition acreage
- All wells in inventory are planned as single-section laterals
- Transition to primarily pattern development in 2017
- Average of 6 rigs running in 2017

STACK: A Significant Petroleum System

Additional development potential in multiple stacked pay zones

Alta Mesa Existing Development

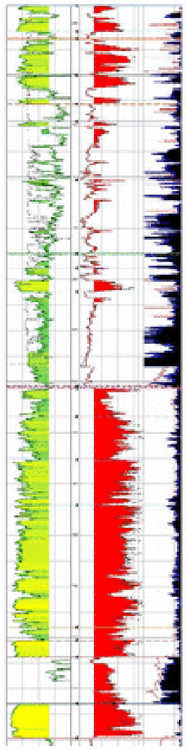
- Existing spacing tests at 660' show full development potential
- 660' spacing tests have more than 200 days of online production
- Over 800 days of strong well performance at spacing of 1,200'
- Three target zones in Osage/Meramec, which represents a continuous 550' section and one additional in Oswego

Additional Zones

- Eight zones have proven hydrocarbon production from vertical wells
- Chester Shale offers added potential
- AMR and others have already drilled successful Oswego, Meramec, Osage, Woodford, and Hunton horizontal wells
- Additional formations, including Big Lime and Red Fork, have horizontal permits and strong vertical production
- Drilling days expected to remain similar across the various formations
- AMR drilling Manning Limestone in 2017

Potential 55 Wells per Section

Type Log

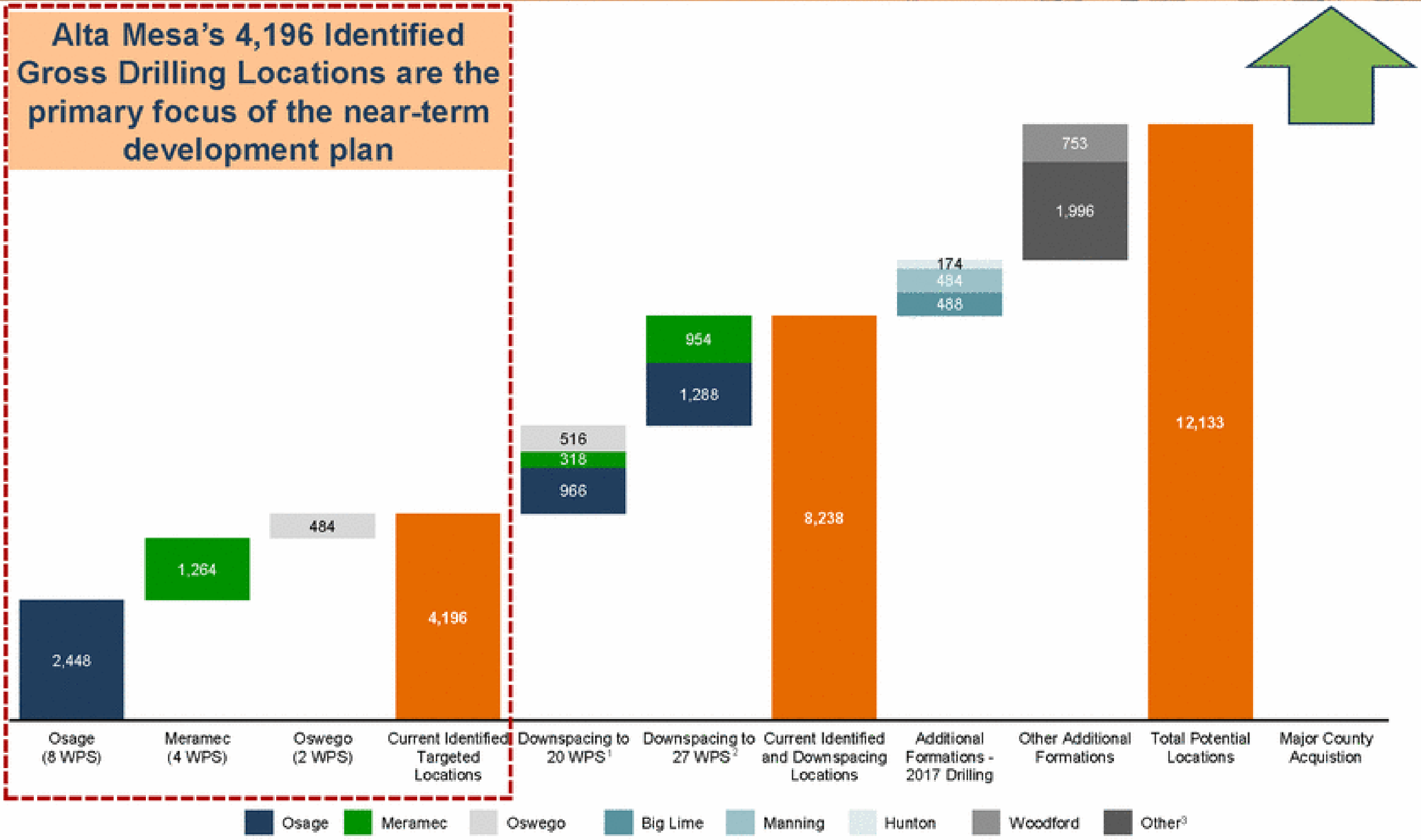


Formation	Targeted	Down-spacing	Additional Formations	Total
Big Lime			4	4
Oswego	2	2		4
Cherokee Shale Prue Sand Skinner Sand Red Fork Sand			4	4
Manning Lime			4	4
Chester Shale			4	4
Meramec	4	4		8
Osage	4	3		7
	4	4		8
Woodford Shale			8	8
Hunton Lime			4	4
Total	14	13	28	55

Note: Actual Alta Mesa log above displays productive formations.

Deep Drilling Inventory

4,196 Identified Gross Locations represent 14+ years of inventory

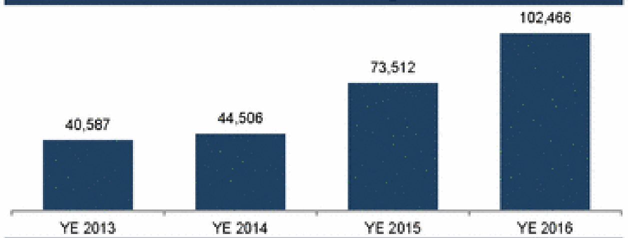


Note: Identified locations based on AMR interest in 320 Meramec/Osage and 257 Oswego sections; excludes additional resource potential or undeveloped locations on ~20,000 net acres recently acquired in the Major County Acquisition.
[1] Low Risk downspacing of Osage to 11 WPS (966 locations), Meramec to 5 WPS (318 locations), and Oswego to 4 WPS (516 locations).
[2] Additional downspacing of Osage to 15 WPS (1,288 locations) and Meramec to 8 WPS (954 locations).
[3] Other Formations include Cherokee and Chester.

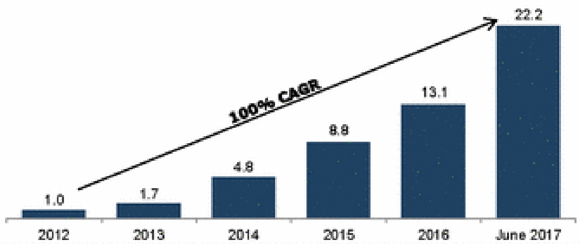
Progressive Execution

Track record of growth in production, reserves, acreage position

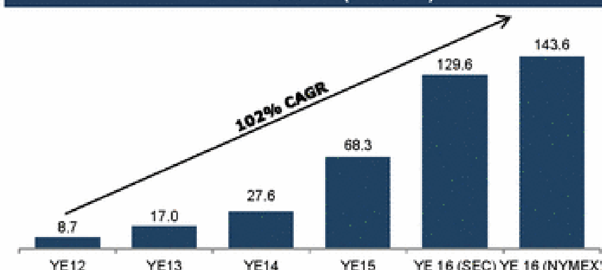
Net STACK Acreage



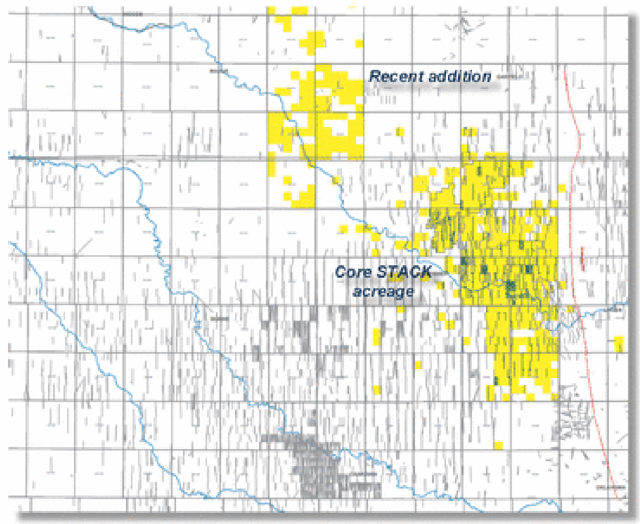
Total Net Production (MBOE/D)[1]



Proved Reserves (MMBOE)[2,3]



Alta Mesa Footprint



- Acreage has grown from ~40,000 net acres to ~120,000 net acres since 2013
- Disciplined acreage aggregation focused primarily on "bolt-on" acquisitions to systematically increase contiguous position
- July 2017 added ~20,000 net acres in Major, Blaine, and Kingfisher; geologic character similar to central-eastern Kingfisher acreage

Source: Company data, Public Filings, IHS Herolds, RigData.

[1] Inclusive of Net Production from Bayou City JV. 2012 and 2013 data reflects occurrence date and not accounting date LOS, due to the reasoning that occurrence date method incorporated a change in NGL accounting; whereas accounting date LOS does not.

[2] YE 2016 proved reserves as of 12/31/2016 close.

[3] YE12-15 proved reserves based on NYMEX pricing.

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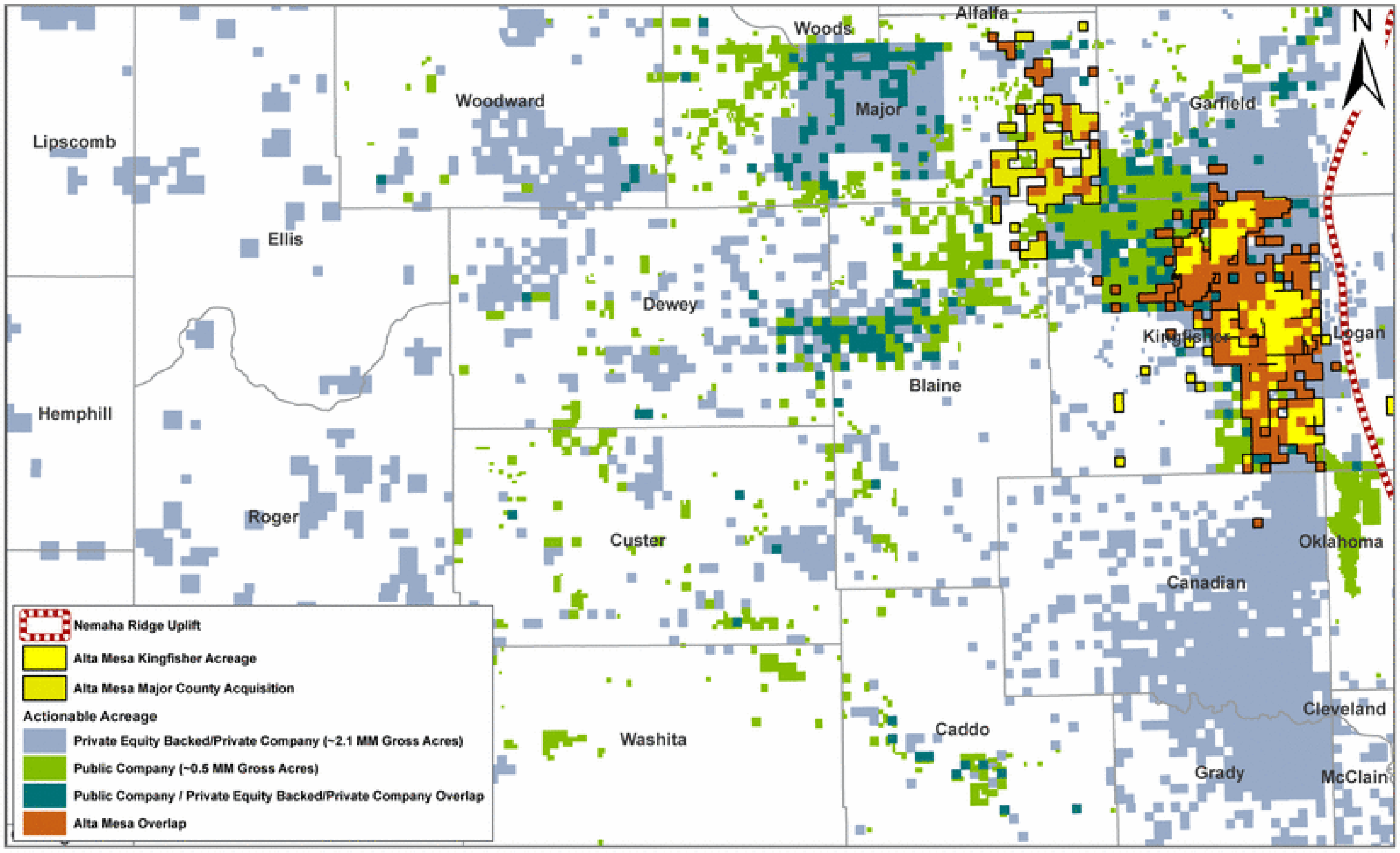
Near Term Consolidation Opportunity

Play is expanding and significant acreage could change hands



Source: Investor Presentations, 1Derrick.

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Our Midstream Assets

KFM is Value Accretive to Alta Mesa

Vertical integration yields substantial strategic and financial benefits

Rapidly Expanding G&P Complex in the Heart of the STACK	• KFM is positioned to capture volume growth from the STACK • Acreage dedications / resource allocations of ~300,000 gross acres
Gathering, Processing and Market Access Support Production Growth	• Total processing capacity is expected to be 340 MMCF/D in 4Q 2017, including 80 MMCF/D of additional offtake • Substantial firm transport to support future growth
Bundled Natural Gas Residue Solution Enhances Marketability	• KFM capable of providing takeaway solutions to end-markets today • KFM has secured firm takeaway capacity on PEPL and OGT
Competitive Advantage in Acquisitions	• KFM well positioned to serve other operators; major gas pipeline projects recently announced by others will be more costly and less timely • Modern processing recoveries and priority residue access to premium markets should result in higher netbacks
KFM's Expansion Offers Complementary, High-Growth Development Project	• Expansion focused on the next stage of STACK development • Limited G&P infrastructure provides opportunity for KFM expansion • KFM involved in negotiations with anchor customers
Midstream Business Can Support Future Capital Needs	• Volumetric growth from third-party development provides upside • Attractive trading multiples and GP/IDR optionality / currency • Future opportunity to monetize KFM and fund upstream capital needs through an MLP IPO, drop downs, and GP / IDR distributions

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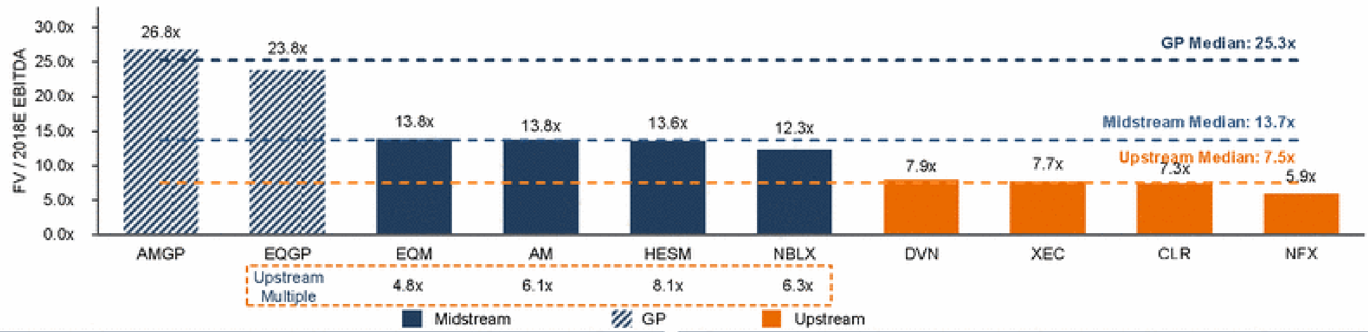
Market Multiples for Midstream Higher than Upstream

Alta Mesa owners to capture GP / IDR cash flow / multiple arbitrage

Valuation Arbitrage

- Likely valuation uplift (multiple arbitrage vs. traditional peer group)



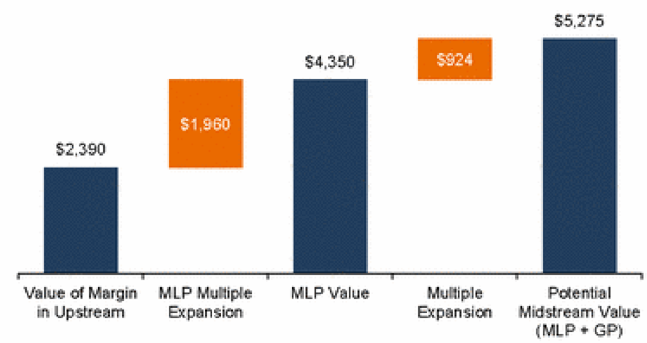
Illustrative Value Accretion from GP Structure

- Potential to continue to benefit from cash flows through retained LP, GP, and IDR ownership interest

	Upstream	Midstream	GP	
EBITDA	$1.0	$1.0	$1.0	
Splits	100%	100%	75%	25%
Multiple	7.5x	13.7x	13.7x	25.3x
Implied Value	$7.5	$13.7	$10.3	$6.3
Uplift	--	1.8x	2.2x	

Illustrative Midstream Value Creation[1]

($ in millions)



[1] Illustrative KFM future value expansion assuming KFM 2019E EBITDA of $318mm.

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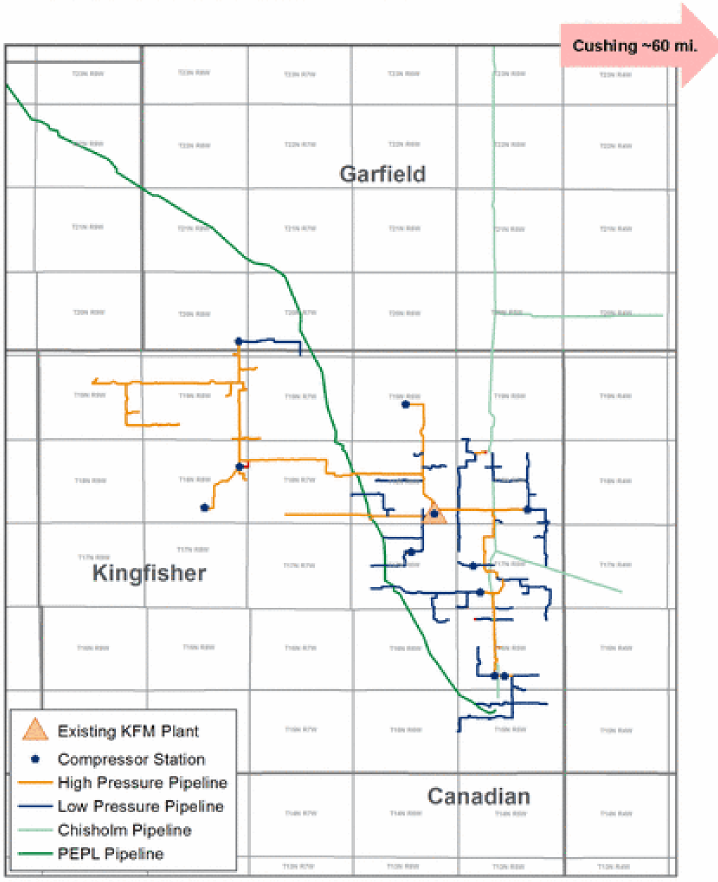
Kingfisher Midstream Summary
Existing Infrastructure



Natural Gas Processing	• Current processing capacity of 60 MMCF/D • Second 200 MMCF/D plant under construction • 80 MMCF/D offtake processing expected 3Q 2017 • 1,200 BBL/D condensate stabilizer
Low Pressure Pipeline	• 223 miles[1] of low-pressure crude and gas gathering lines – Natural gas gathering: 6"-16" pipeline – Crude gathering: 6"-8" pipeline
High Pressure Pipeline	• 98 miles[2] of 4" to 16" rich gas transportation pipeline – Average operating pressure of 1,100 psig and piggable • 4 miles of 16" residue gas pipeline with 230 MMCF/D of capacity to PEPL • 5 miles of 16" residue gas pipeline connecting KFM to OGT in service October 2017 • 4 miles of 6" NGL Y-grade pipeline, with 10,000 BBL/D capacity to Chisolm Pipeline
Compression Facilities	• Field Compression – 3 CAT 3516s at Lincoln South Location (4,140 total horse power) – 3 CAT 3516s at WSOR Location (4,140 total horse power) – 1 CAT 3516, 1 CAT 3306 at Garfield Compressor Site – 1 CAT 3508 at Snowden Compressor Site – 1 CAT 3516 at West Kingfisher Compressor Site – 1 CAT 3508 at Great Divide Compressor Site • Inlet Compression – 6x CAT 3606s (10,650 total horse power) • Residue Compression - 3x CAT 3516s (4,140 total horse power)
Other Infrastructure	• 50,000 BBL crude storage with 6 truck loading LACTS • 3 NGL bullet tanks: 90,000 gallon capacity
Producer Connections	• 54 central delivery point receipt connections serve 188 units

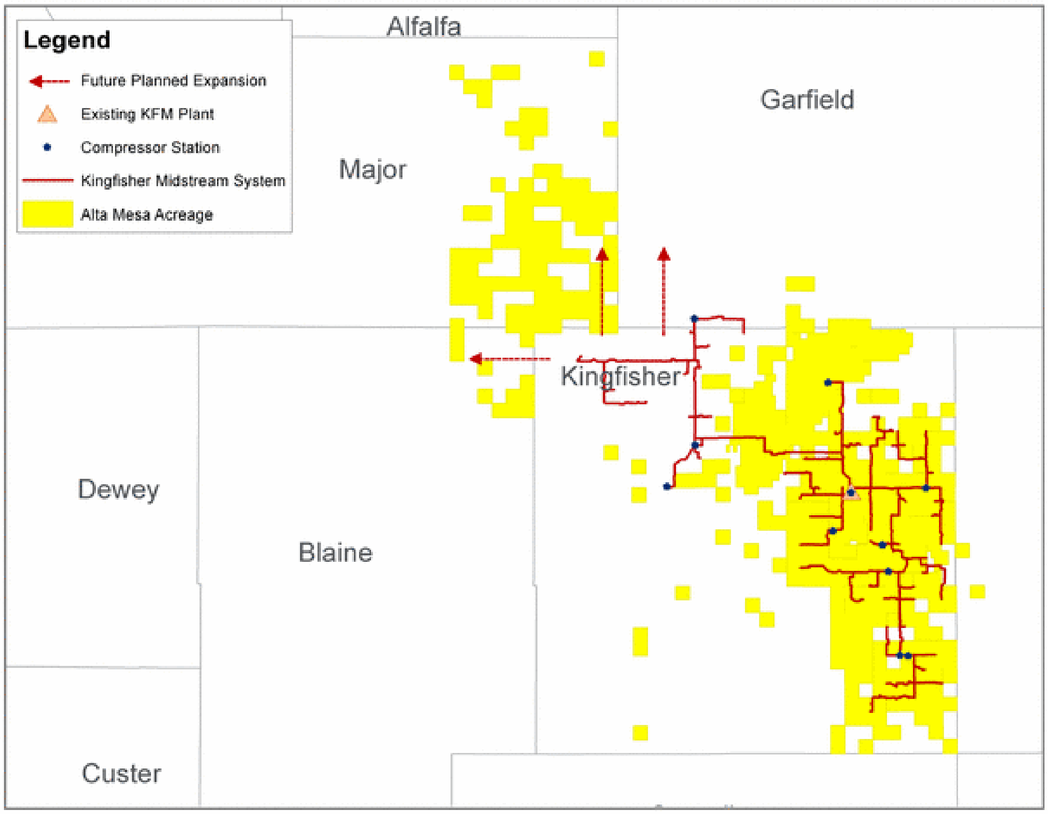
Note: Represents multiple lines in ditch.
[1] Includes 16 miles under construction
[2] Includes 20 miles under construction

KFM Midstream Takeaway Overview

	Pipeline	Description	Current Takeaway Capacity	Expansion Projects	Commentary
Natural Gas		• Connected to PEPL – owned and operated by Energy Transfer • PEPL consists of four large diameter pipelines extending approximately 1,300 miles throughout Mid-Continent and other market centers • KFM will connect to OGT Q3 2017 • OGT services local Oklahoma gas demand, but via on expansion will begin to deliver gas to WAHA in Q2 2018	• 100,000/day FT on PEPL • 50,000/day FT on OGT, expanding to 125,000/day June 2018 – 25,000 Dth/d for 4 years – 100,000 Dth/d for 10 years	• KFM in discussion with all proximate outlet pipelines looking to expand out of the basin	• Gas takeaway is functionally full creating a constrained environment for some producers. KFM's residue position provides flow assurance and better netbacks for KFM producer clients • Residue gas is split connect between PEPL and OGT, and under long term agreements insuring that KFM producer customers can flow out of the basin • Capacity rates are low compared to new rates that will be needed to solidify new capacity out of the basin creating better netbacks for KFM producers dedicated to the system
NGL		• Connected to Chisholm Pipeline - operated by Phillips 66 • Delivers NGLs to Conway	• Operational capacity of ~41,000 Bbls/d on existing Chisholm line • Currently under a 3 year contract extendable for 2 1-year terms with shipper history	• Opportunity to tie into other NGL pipelines in the area • Volumes could warrant expansion or new build to Mt. Belvieu	• Connected to P66's Chisolm Y-grade pipeline that takes Y-grade to Conway, KS for fractionation • Multiple NGL lines within 7 miles of plant to further diversify Y-Grade options when needed • KFM Y-grade optionality will allow producers to capture netback uplift between Conway, KS and Mt Belvieu
Crude		• Crude gathered to a central delivery point at the plant site • Six truck bays for LACT loading and unloading • Multiple pipeline connection options	• Not currently committed	• Long haul pipeline opportunities to Cushing and other demand sources in the area	• Crude system is focused around keeping Alta Mesa barrels and future third party barrels clean to market, producing better netbacks • Proximity to Cushing provides market optionality between in-state and the Gulf Coast refineries. • No long terms commitments provide KFM the option to build out long-haul crude pipelines enhancing drop down inventory

KFM Phase III Expansion Overview

- Recent Major county acquisition adds scale through ~20,000 acre dedication
- Offset operator activity in the Western STACK reflects compelling economics driving producer interest and investment
- KFM has identified and plans to capitalize on this midstream opportunity and is rapidly commercializing this growth initiative
- KFM is in the process of securing acreage dedications and other resource allocations in the Western STACK




Financial Summary

Financial Strategy and Pro Forma Financial Impacts

Significant Financial Flexibility

- Demonstrated trajectory to positive free cash flow with near-term development funded with transaction proceeds
- Secure robust liquidity to fund development, with near-term production growth ensured by KFM takeaway capacity
- Pro forma for this transaction, financial flexibility in place to pursue opportunistic acquisitions with a goal toward consolidation of the STACK region

Maintain Conservative Balance Sheet

- Maintain conservative credit metrics of < 2.0x leverage through the cycle
- Preserve an optimal debt maturity profile
- Maintain simplified balance sheet

Protect Cash Flow

- Prudent capital budget focused on securing leasehold and developing existing acreage
- Ensure capital budget is flexible to future changes in commodities and/or service costs
- Continued rolling hedge strategy to protect revenues and support development program

Capitalization at Announcement

	Current			
($ in millions, unless specified)	Alta Mesa	KFM	Adjustments	Pro Forma
Cash and Cash Equivalents	$5	$28	$517[1]	$551
Revolving Credit Facility	269[2]	$0	(269)[2]	0
7.875% Senior Notes due 2024	500			500[3]
Total Debt	$769	$0	($269)	$500
Net Debt	763			(51)
Financial and Operating Statistics				
2017E EBITDA	$155	$42		$197
2018E EBITDA	358	184		543
2019E EBITDA	701	318		1,019
Credit Metrics				
Net Debt /				
2017E EBITDA				NM
2018E EBITDA				NM
2019E EBITDA				NM
Liquidity				
Expected Borrowing Base	$315	$200		$515
Less: Amount Drawn	269		(269)	0
Expected Borrowing Base Availability	$46			$515
Plus: Cash and Cash Equivalents	5			551
Liquidity	$52			$1,066

[1] Cash to balance sheet includes funding for interim cash needs until closing.
[2] Current revolving credit facility balance as of 8/10/2017 does not include approximately $5mm of letters of credit.
[3] Change of control not triggered for 2024 Senior Notes upon execution of transaction.

2017 Capital Budget and Hedge Position

Commentary

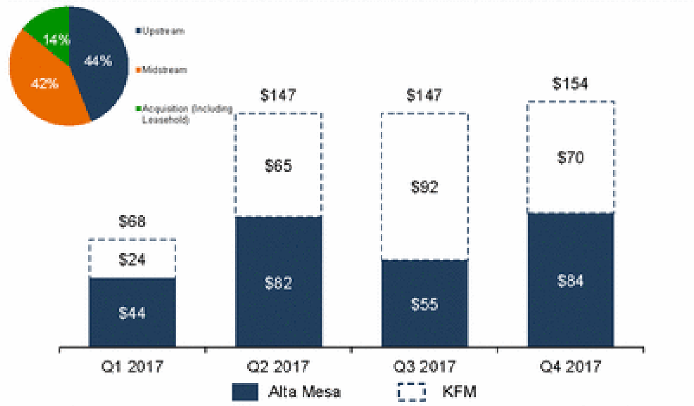
Alta Mesa

- Alta Mesa's 2017 net capital budget is estimated to be $349MM, ~11% higher than capital expenditures of $316MM in 2016
- Alta Mesa estimates that ~$108MM of the FY 2017 capital budget will be funded by Bayou City per the JV agreement
- Alta Mesa's total 2017 capital budget is estimated to be $458MM, including the Bayou City Energy JV
- FY 2017 acquisition (including leaseholds) capex spending expected to total $85MM, or ~19% of the total deployed budget (including Bayou City Energy JV)
- Expect 10-Rig program in the STACK by YE18
- Continue growth and efficiency gains in the STACK while maintaining conservative Leverage Ratio

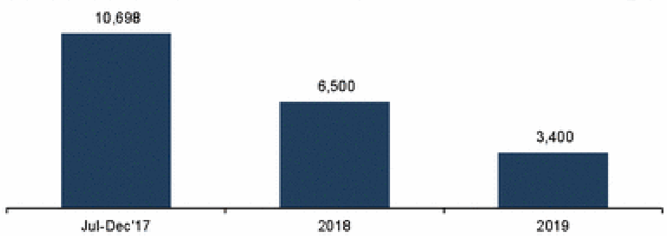
Kingfisher Midstream

- KFM's 2017 net capital budget is estimated to be $251MM
- Growth capital categorized through processing, pipeline, high / low pressure well connects, compression lease principal payments and compression lease interest expense items

2017E Capital Budget by Quarter ($MM) – Excl. Acquisitions[1]

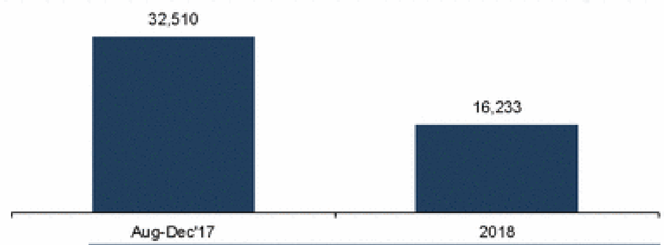


Oil Hedged (BBL/D) – as of 6/30/17



	Jul-Dec'17	2018	2019
Average Floor Price ($/BBL)	$49.55	$51.67	$50.00

Gas Hedges (MCF/D) – as of 6/30/17



	Aug-Dec'17	2018
Average Floor Price ($/BBL)	$3.18	$4.43

Disciplined management protects future revenues and preserves asset value by hedging large percentage of proved-developed and prompt-year production. Currently hedge WTI (oil), Henry Hub (gas), Conway (propane), and Mid-Con gas basis.

[1] Does not include Bayou City Energy JV.

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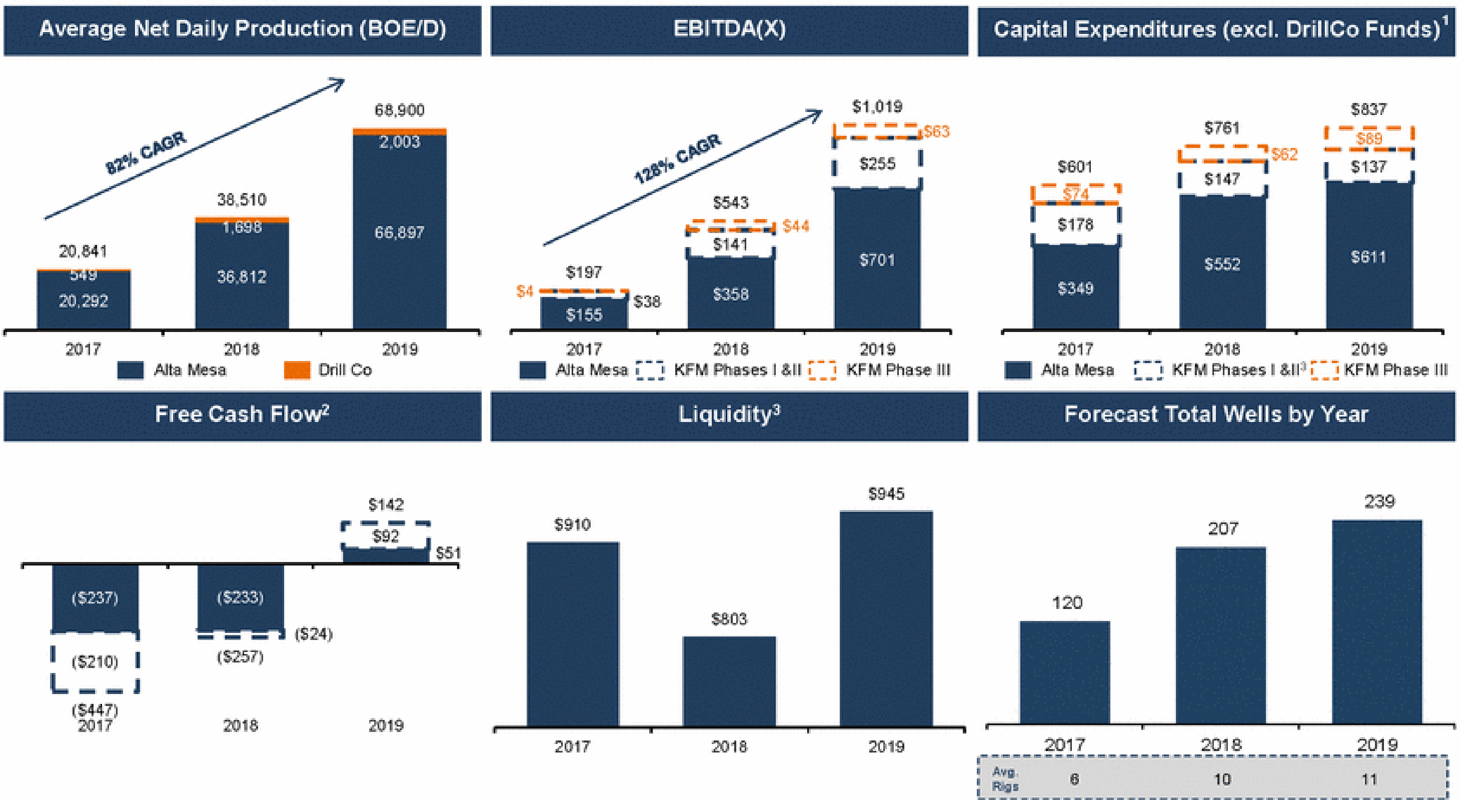
Valuation and Timeline

Summary Financial Projections

($ in millions unless otherwise noted)



Note: Assumes Broker Consensus Price Deck (2017: $51.16/bbl / $3.16/mcf, 2018: $54.90/bbl / $3.14/mcf, 2019: $58.00/bbl / $3.05/mcf and held flat thereafter).
[1] DrillCo Funds is Bayou City JV deal.
[2] Phase I & II capex includes planned, non-optional Phase III capex.
[3] Assumes borrowing base increase from $515mm to $665mm in 2018 and includes funding for interim cash needs until closing and KFM revolving credit facility. Assumes combined FCF deficit of ($155)mm from current until year-end 2017.

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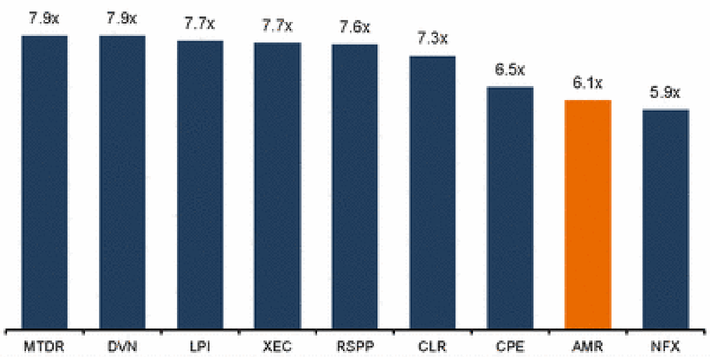
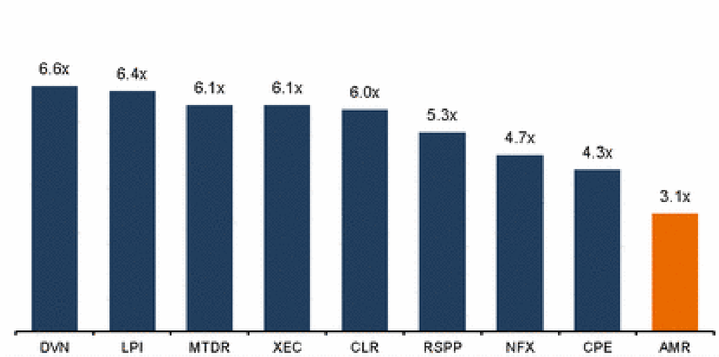
Valuation Benchmarking

($ in millions unless otherwise noted)

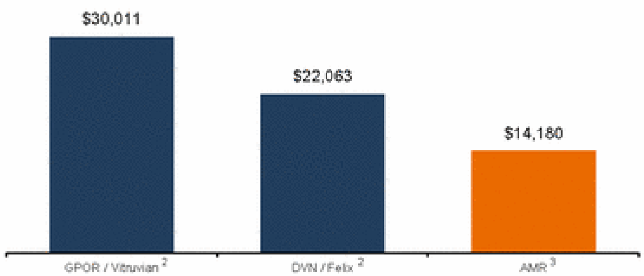
Firm Value / 2018E EBITDA



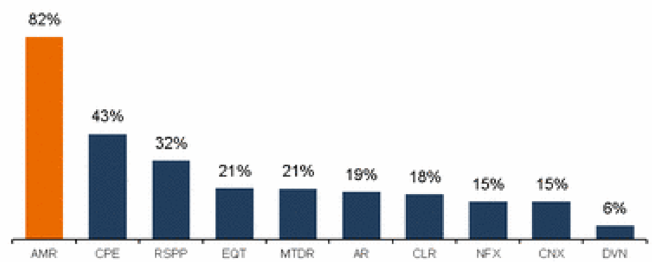
Firm Value / 2019E EBITDA



Adjusted Firm Value[1] / Net Acres



2017E – 2019E Production CAGR

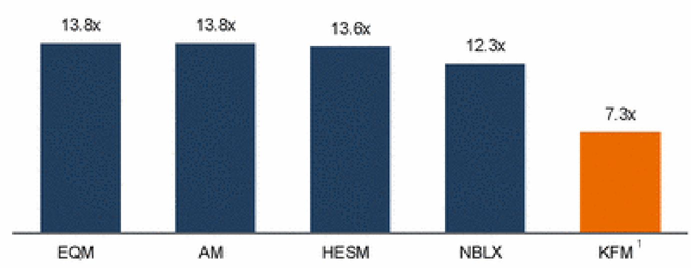


[1] PDP value adjusted at $30,000 / BOE/D unless otherwise noted.
[2] PDP value adjusted at $15,000 / BOE/D.
[3] Alta Mesa PDP value assumes Broker Consensus Price Deck (2017: $51.16/bbl / $3.16/mcf; 2018: $54.90/bbl / $3.14/mcf; 2019: $58.00/bbl / $3.05/mcf and held flat thereafter). Excluding the Major County acreage, our adjusted $ / net acre is $17,158 / acre.

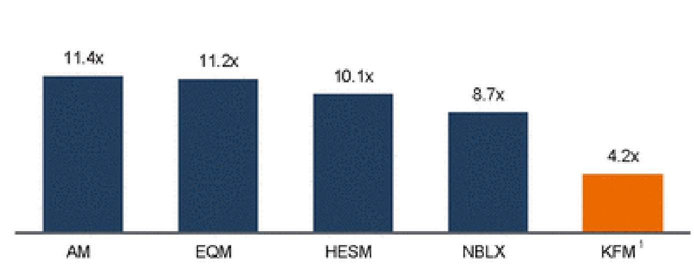
Benchmarking KFM Against High Growth G&P Peers

($ in millions unless otherwise noted)

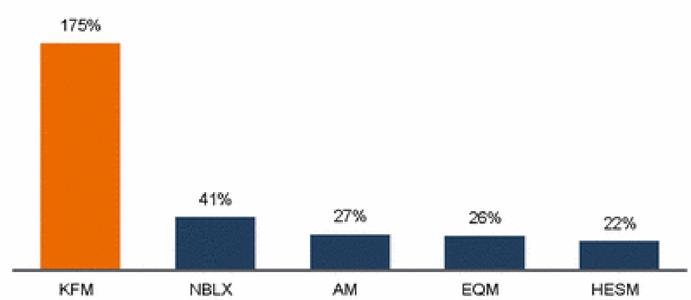
Firm Value / 2018E EBITDA



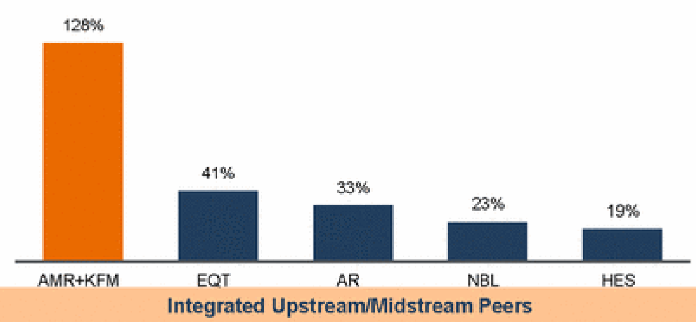
Firm Value / 2019E EBITDA



Midstream 2017E – 2019E EBITDA CAGR



Consolidated 2017E – 2019E EBITDA CAGR



[1] Includes midstream Firm Value only.

Anticipated Transaction Timeline

Date	Event
Weeks of September 4^{th} – September 29^{th}	• Transaction marketing
Mid-September 2017	• File preliminary proxy statement / marketing materials with the SEC
Mid/Late-November 2017	• Anticipated close

Pure Play STACK Company

Premier liquids upstream growth with value-enhancing midstream

- World class asset with attractive geology
- Top-tier operator with substantial in-basin expertise
- Industry-leading growth potential; 2-year expected EBITDA CAGR of 128%
- Highly strategic and synergistic midstream subsidiary with Kingfisher Midstream
- Financial strength and flexibility to execute business plan through the cycle; cash flow positive in 2019


Appendix

Alta Mesa Management

Jim Hackett

Executive Chairman and COO of Midstream

- Jim Hackett is a Partner at Riverstone and became a director of Silver Run II in 2017
- Prior roles include:
  - Chairman and CEO of Anadarko
  - President and COO of Devon Energy
  - Chairman, President and CEO of Ocean Energy
  - President of several midstream companies, as well as responsible for DCP Midstream and Western Gas Resources
- Director of Enterprise Products Holdings, Fluor Corporation, National Oilwell Varco, Sierra Oil & Gas, and Talen Energy
- Former Chairman of the Board of the Federal Reserve Bank of Dallas
- Holds a B.S. from the University of Illinois and a MBA/MTS from Harvard University

Hal Chappelle

President and Chief Executive Officer

- Hal Chappelle joined Alta Mesa as President and CEO in 2004 and became a director in 2004
- Developed Alta Mesa into a premier STACK operator, building a strong management and technical team
- Successfully navigated Alta Mesa through significant industry cycles, building the Company's oil assets in 2009-2010 and divesting of the company's gas assets in 2014-2016
- Over 30 years of industry experience in field operations, engineering, management, trading, acquisitions and divestitures, and field re-development
- Previously held roles at Louisiana Land & Exploration, Burlington Resources, Southern Company and Mirant
- Holds a Bachelor of Chemical Engineering from Auburn University and an M.S. in Petroleum Engineering from the University of Texas

Michael McCabe

Vice President and Chief Financial Officer

- Michael McCabe joined Alta Mesa in 2006 and became a director in 2014
- Raised private equity capital for Alta Mesa from Denham Capital in 2006, HPS Investment Partners in 2013, and Bayou City in 2015; successfully navigated Alta Mesa through two industry cycles
- Has over 25 years of corporate finance experience with a focus on the energy industry
- Previous management experience includes serving as President and sole owner of Bridge Management Group, Inc., a private consulting firm
- Mr. McCabe's leadership experience also spans senior positions with Bank of Tokyo, Bank of New England and Key Bank
- Holds a B.S. in Chemistry and Physics from Bridgewater State University, an M.S. in Chemical Engineering from Purdue University, and an MBA from Pace University

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Alta Mesa Management

Michael Ellis

Founder and COO of Upstream Operations

- Michael Ellis founded Alta Mesa in 1987 after beginning his career with Amoco
- Served as Chairman and COO as well as Vice President of Engineering and has over 30 years of experience in management, engineering, exploration, and acquisitions and divestitures
- Built Alta Mesa's asset base by starting with small earn-in exploitation projects, then growing with successive acquisitions of fields from major oil companies
- Holds a B.S. in Civil Engineering from West Virginia University

Gene Cole

VP and Chief Technical Officer

- Gene Cole has served in the position of Vice President and Chief Technical Officer since 2015 and became a director in 2015
- Over 25 years of extensive domestic and international oilfield experience in management, well completions, well stimulation design and execution
- Started his career with Schlumberger Dowell as a field engineer and served in numerous increasingly responsible positions from 1986 to 2007
- Holds a B.S. in Petroleum Engineering from Marietta College

David Murrell

VP, Land and Business Development

- David Murrell has served as Vice President, Land and Business Development since 2006
- Over 25 years of experience in Gulf Coast leasing, exploration and development programs, contract management and acquisitions and divestitures
- Created a structured land management system for Alta Mesa and built a team of lease analysts, landmen, and field representatives to facilitate Alta Mesa's growth
- Holds a B.B.A in Petroleum Land Management from the University of Oklahoma

Kevin Bourque

VP, Operations

- Kevin Bourque progressed through several roles to the position of Vice President of Mid-Continent Operations in 2012 when we began STACK horizontal drilling program
- He joined Alta Mesa as a field engineer in 2007
- Led the growth of our mid-continent drilling and production operations as we expanded our presence in Oklahoma
- 10+ years of E&P operational experience with Alta Mesa
- 10+ years of project management and business management experience as the owner of his own company

Tim Turner

VP, Corporate Development

- Tim Turner joined Alta Mesa as Vice President of Corporate Development in 2013
- Over 30 years of industry experience including various operations, reservoir engineering and managerial roles with Sun Oil, Santa Fe Minerals, Fina Oil & Chemical, Total, Newfield Exploration, and Quantum Resources
- Led multi-disciplined A&D and asset teams
- Managed corporate reserves and planning functions
- Led business development and new ventures teams
- Holds a B.S. in Petroleum Engineering from the University of Texas and an MBA in Finance from Oklahoma City University

David McClure

VP, Facilities & Midstream

- David McClure has served as Vice President of Facilities and Midstream Operations since 2016
- From 2010 to 2016, he was Vice President for Louisiana Operations, leading a multi-disciplined team of engineers, regulatory, land, geoscience, and operations personnel in development of the Weeks Island field
- Previously held roles at ExxonMobil Production Company and Tetra Technologies
- Over 15 years of industry experience in field operations, facilities and subsea engineering, pipelines, and management
- Holds a B.S. in Chemical Engineering from Auburn University

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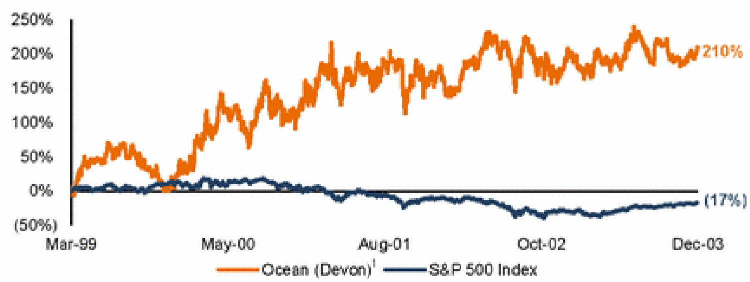
Jim Hackett's Track Record

Under Mr. Hackett's leadership as Chairman, President, and/or CEO of Anadarko from 2003 to 2013, Anadarko was transformed into one of the largest U.S. oil and gas producers, growing its market cap from approximately $12 billion to over $43 billion. Prior to Anadarko, Mr. Hackett was also a key contributor to the market outperformance of Devon Energy.

Anadarko Public Market Outperformer (2003 – 2013)

Ocean (Devon)[1] Public Market Outperformer (1999 – 2003)



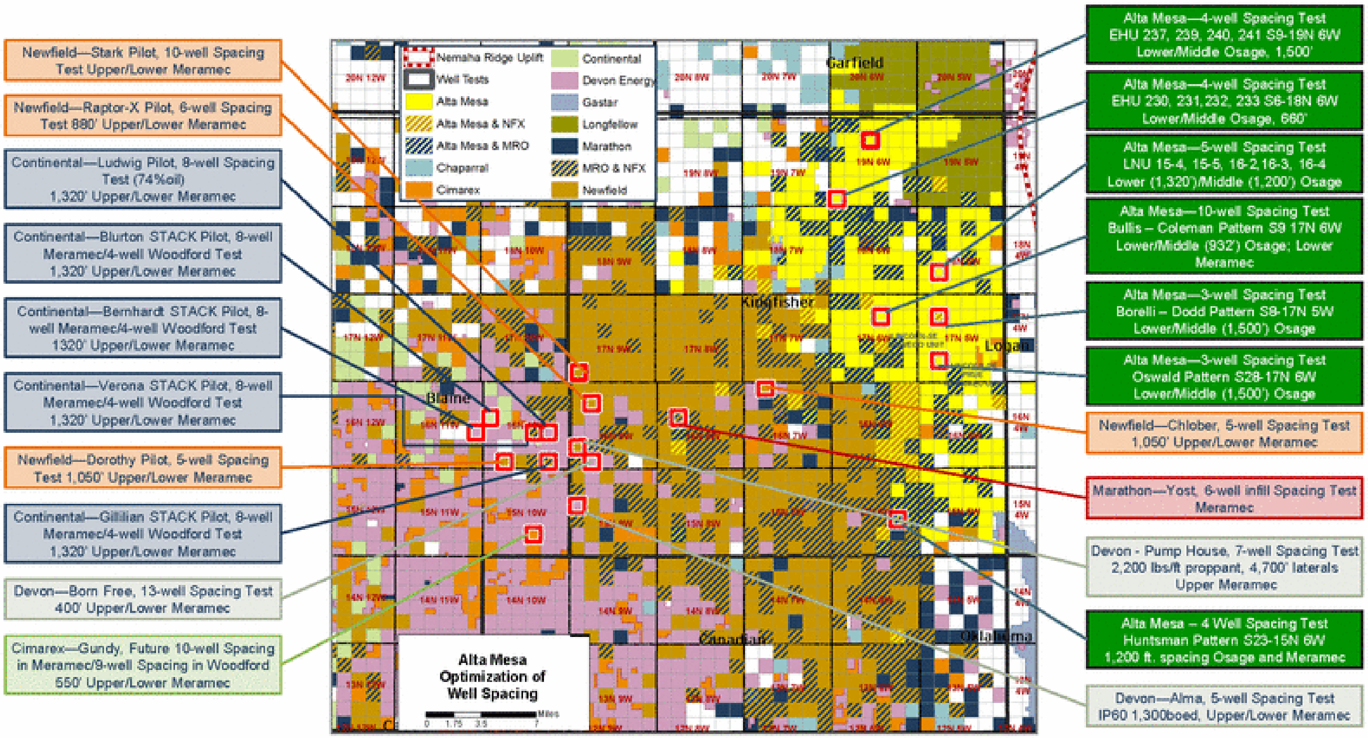
Strategic Thought Leader	• Created new mission for Anadarko in 2003, upgraded corporate leadership capabilities, rationalized and refocused the portfolio, improved technical and financial risk management tools and processes, and generated success through expansion into unconventional onshore and conventional offshore assets • Applied leading-edge technology and processes in drilling, completions, and production • Dynamic leader for years serving as President and COO of Devon Energy, Chairman, President and/or CEO of Ocean Energy, president of several midstream companies, responsible for Duke Energy and PanEnergy's midstream and upstream businesses, and drove Anadarko's midstream business consolidation and MLP/GP IPO – Western Gas Partners and Western Gas Resources
Benchmark for Operational Excellence and Execution	• Premier operator with some of the best production metrics in U.S. onshore, U.S. Gulf of Mexico, and offshore East Africa

Source: FactSet.
Note: An investment in Silver Run Acquisition Corporation II is not an investment in Anadarko or Devon. The results of Anadarko or Devon are not necessarily indicative of the future performance of Silver Run Acquisition Corporation II.
[1] Chart displays Ocean share price performance until merger with Devon completed. Thereafter, chart shows Devon performance on a per-Ocean share basis.

Well Spacing Optimization on De-Risked Acreage

DVN, CLR, MRO, NFX and AMR aggressively defining optimum spacing

Alta Mesa is the Leader in the Oil Window with Successful Long Life Spacing Tests



Source: 1Derrick, IHS, Drilling Info and Company Presentations.

Completion Design

Focus on increasing stimulated reservoir volume

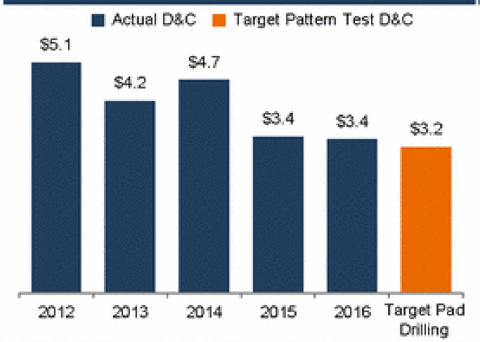
STACK Well Completion Strategy

- Progressed through testing multiple generations
- Highly fractured area benefits from "open-hole" design
- Targeting average lateral length of 4,800ft (one-mile)
- Drilling N–S orientation to intersect natural fractures
- Controlled flowback rate to optimize conductivity
- Generation 2.5 proppant loading is optimum at an average of 1,400 lb/ft; tested up to 2,100 lb/ft

Current Completion Design Targets

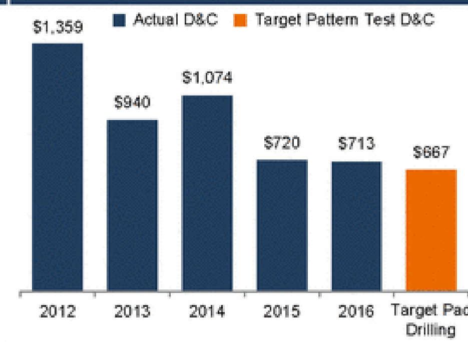
- 7" intermediate casing + 4.5" liner in lateral
- Open-hole swell packers; proppant loading of 1,400 lbs/ft
- 3 joints (casing) between packers defines 150ft stages
- 10,000 bbls of slick water per stage
- 100 bbl/min total fluid injection rate
- Cap flowback rate at 100 bbl/hr of total fluid

Total D&C Cost ($MM)



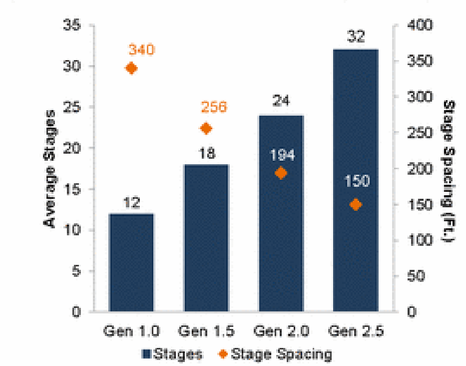
Avg. Days Spud to TD	46	34	25	17	13	13

D&C Cost / Lateral Foot

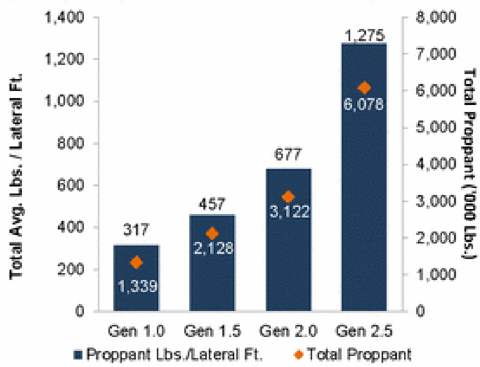


Averages by Completion Generation

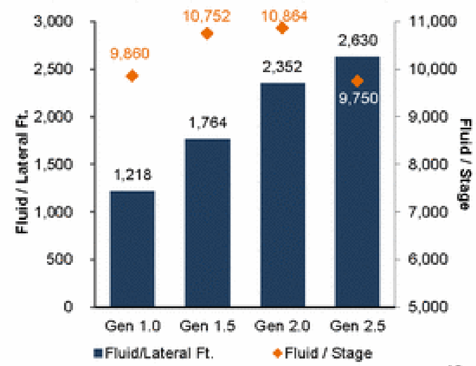
Stage Spacing



Proppant



Fluid



Source: Company Data.

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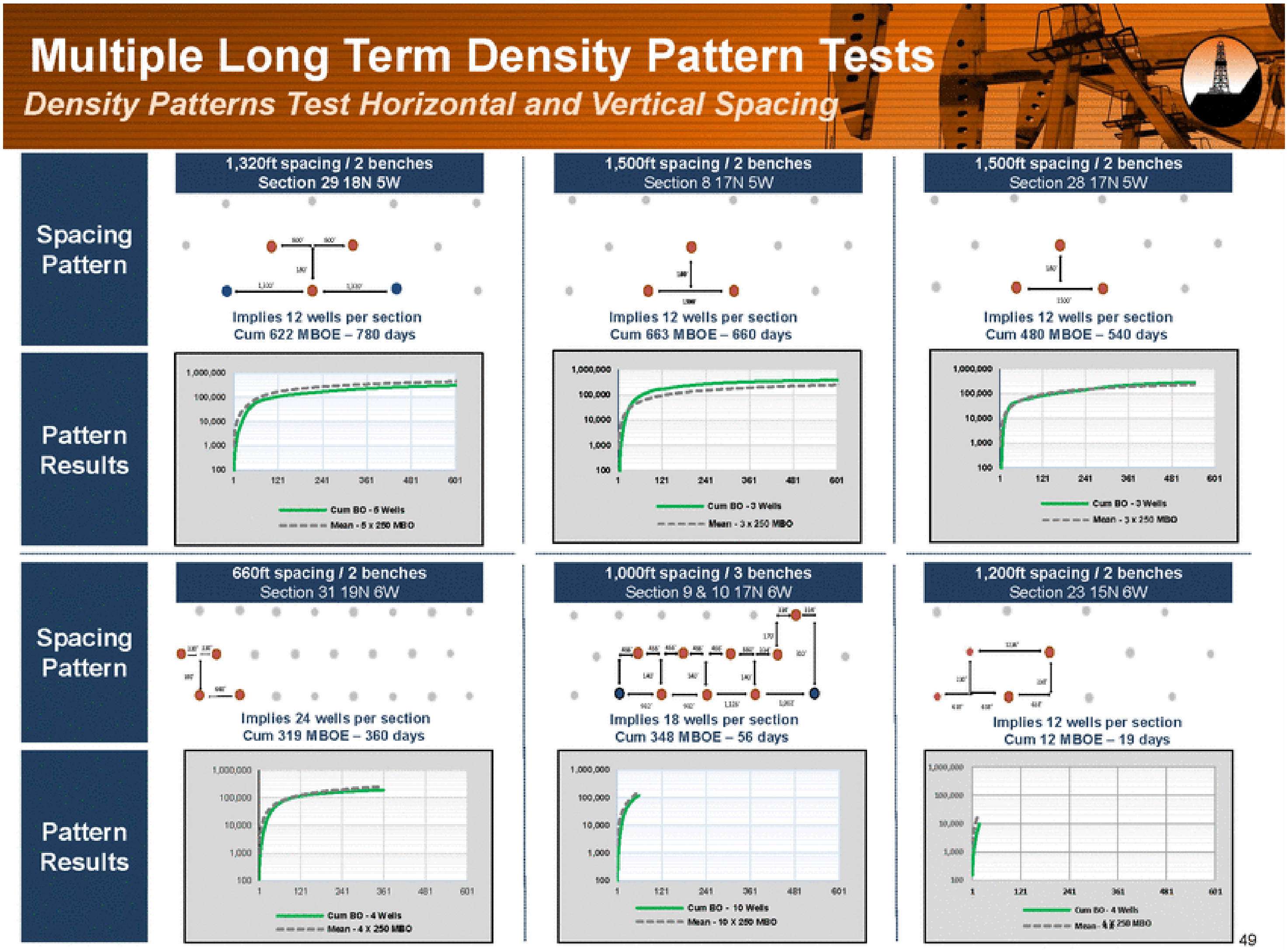

Multiple Long Term Density Pattern Tests
Density Patterns Test Horizontal and Vertical Spacing
Spacing Pattern
Pattern Results
1,320ft spacing / 2 benches
Section 29 18N 5W
Implies 12 wells per section
Cum 622 MBOE – 780 days
Cum BO - 5 Wells
Mean - 5 x 250 MBO
1,500ft spacing / 2 benches
Section 8 17N 5W
Implies 12 wells per section
Cum 663 MBOE – 660 days
Cum BO - 3 Wells
Mean - 3 x 250 MBO
1,500ft spacing / 2 benches
Section 28 17N 5W
Implies 12 wells per section
Cum 480 MBOE – 540 days
Cum BO - 3 Wells
Mean - 3 x 250 MBO
660ft spacing / 2 benches
Section 31 19N 6W
Implies 24 wells per section
Cum 319 MBOE – 360 days
Cum BO - 4 Wells
Mean - 4 X 250 MBO
1,000ft spacing / 3 benches
Section 9 & 10 17N 6W
Implies 18 wells per section
Cum 348 MBOE – 56 days
Cum BO - 10 Wells
Mean - 10 X 250 MBO
1,200ft spacing / 2 benches
Section 23 15N 6W
Implies 12 wells per section
Cum 12 MBOE – 19 days
Cum BO - 4 Wells
1,000,000
100,000
10,000
1,000
100
1
121
241
361
481
601
49

NAV Model Assumptions

Area	Operated: Osage	Operated: Meramec	Operated: Oswego	Other: DrillCo
Pricing & Discount Assumptions				
Gas Differential *(% of HH)*	95%	95%	95%	95%
Oil Differential *(% of WTI)*	94%	94%	94%	94%
NGL Realization *(% of WTI)*	45%	45%	45%	45%
Drilling Assumptions				
Number of Drilling Locations	2,388	1,264	484	60
Working Interest - Operated *(%)*	72%	74%	75%	57%
Working Interest - Other *(%)*	15%	15%	13%	--
NRI - Operated *(%)*	60%	61%	62%	47%
NRI - Other *(%)*	12%	12%	11%	--
Fixed Operating Cost *($k/well/month)*	$9.7	$9.7	$9.7	$9.7
Variable LOE *($ / bbl of oil)*	$2.23	$2.23	$2.23	$2.23
Gas Marketing & Transportation *($ / mcf of gas) - Until 2021*	$0.35	$0.35	$0.35	$0.35
Gas Marketing & Transportation *($ / mcf of gas) - Thereafter*	$0.35	$0.35	$0.35	$0.35
Initial Production Tax - Oil *(%)*	2.1%	2.1%	2.1%	2.1%
Initial Production Tax - Gas/NGLs *(%)*	2.1%	2.1%	2.1%	2.1%
Severance Holiday *(months)*	36	36	36	36
Production Tax - Oil *(%)*	7.1%	7.1%	7.1%	7.1%
Production Tax - Gas/NGLs *(%)*	7.1%	7.1%	7.1%	7.1%
Ad Valorem Tax *(%)*	0.0%	0.0%	0.0%	0.0%
Drilling & Completion Cost *($mm)* [1]	$3.5	$3.5	$2.5	$0.3
EUR Assumption				
Gross EUR				
Gross Sales Gas EUR (MMcf)	1,571	1,425	168	1,571
Gross NGL EUR (Mbbl)	141	128	15	141
Gross Oil EUR (Mbbl)	250	249	200	250
Total Gross EUR (Mboe)	652	615	243	652
Type Curve Assumptions				
Oil				
IP, 24-hr (Bbl/d)	200	170	320	200
Duration of Incline (Months)	2	2	--	2
Peak Rate (Bbl/d)	350	500	320	350
B Factor	1.20	1.20	1.20	1.20
Di-Continuous (Nominal) Decline (%)	73%	80%	72%	73%
Terminal Decline (%)	7%	7%	7%	7%
Natural Gas				
IP, Unshrunk, 24-hr (Mcf/d)	500	296	320	500
Duration of Incline (Months)	4	2	--	4
Peak Rate (Mcf/d)	900	1,250	320	900
B Factor	1.50	1.50	1.20	1.50
1-Di-Continuous (Nominal) Decline (%)	41%	56%	72%	41%
Terminal Decline (%)	5%	5%	7%	5%
NGL Yield (bbls/MMcf)	75	75	75	75
% Gas Shrink	15.9%	16.1%	15.9%	15.9%

DrillCo includes all Osage Wells

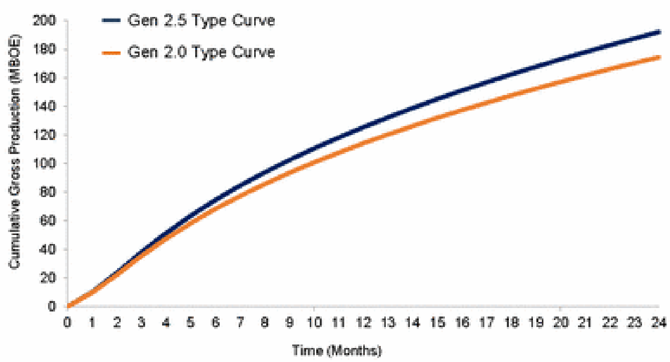
Note: Assumes 4,800 lateral length for all type curves.
[1] D&C shown including PAD D&C facilities costs.

Osage Type Curve

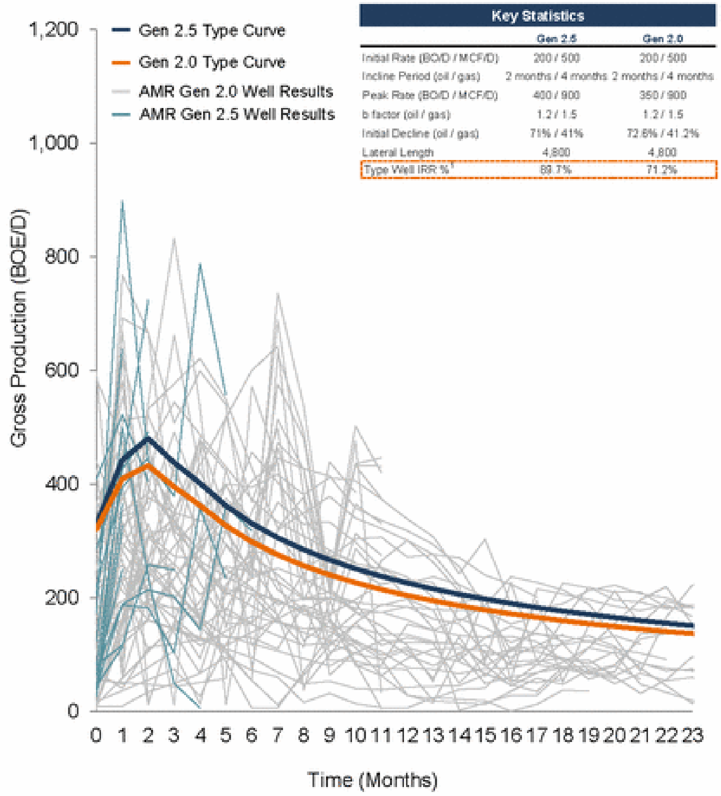
Summary

- 118 Generation 2.0+ wells with production history
- Average Generation 2.5 lateral length of 4,612'; Generation 2.0+ 4,767'
- Type Curve average 30-day IP 0.3 MBOE/D
- Type Curve average 180-day cumulative production of 75 MBOE
- Generation 2.5 Type Curve
  - 622 MBOE 2-Stream EUR; 714 MBOE 3-Stream EUR
  - 303 MBO, 1.6 BCF residue, 144 MB NGL
- Generation 2.0 Type Curve
  - 561 MBOE 2-Stream EUR; 652 MBOE 3-Stream EUR
  - 250 MBO, 1.6 BCF residue, 141 MB NGL
- Type Curves assume 16% Shrink and 75 bbl/MMcf NGL yield

Average Type Curve Cumulative Production



Average Type Curve



Key Statistics

	Gen 2.5	Gen 2.0
Initial Rate (BO/D / MCF/D)	200 / 500	200 / 500
Incline Period (oil / gas)	2 months / 4 months	2 months / 4 months
Peak Rate (BO/D / MCF/D)	400 / 900	350 / 900
b factor (oil / gas)	1.2 / 1.5	1.2 / 1.5
Initial Decline (oil / gas)	71% / 41%	72.6% / 41.2%
Lateral Length	4,800	4,800
Type Well IRR %[1]	89.7%	71.2%

Note: Production data normalized for 4,800' lateral length.

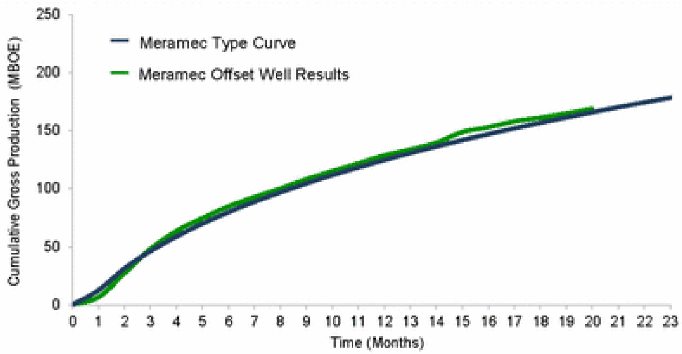
[1] NYMEX Strip as of 8/3/2017. Does not include $300k PAD D&C facilities costs. Adjusted for transportation costs paid to KFM. Excludes $1.25 / bbl oil transportation costs.

Meramec Type Curve

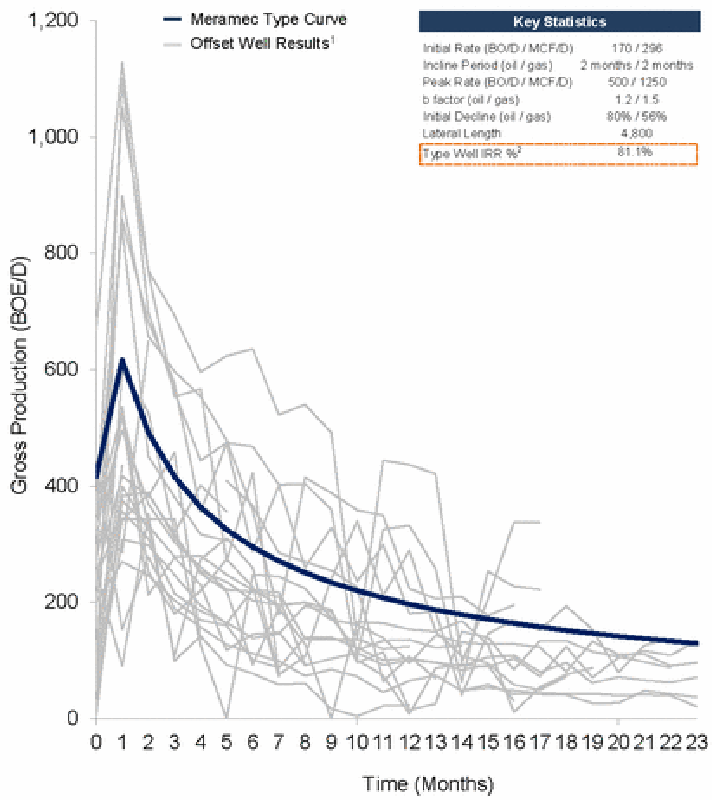
Summary

- Over 100 wells drilled in the Meramec by Newfield, Devon, Marathon, Gastar, and Chaparral
- Alta Mesa is beginning to drill Meramec wells with performance expectations similar to the Osage
- Alta Mesa will be joint developing the Meramec with Osage stack and staggered well tests
- Majority of active rigs in the STACK play are targeting the Meramec to the southwest
- Average Type Curve Results
  - 532 MBOE 2-Stream EUR; 615 MBOE 3-Stream EUR
  - 249 MBO, 1.4 BCF residue, 128 MB NGL
- Type Curve assumes 16% Shrink and 75 bbl/MMcf NGL yield

Average Type Curve Cumulative Production



Average Type Curve



Key Statistics	
Initial Rate (BO/D / MCF/D)	170 / 296
Incline Period (oil / gas)	2 months / 2 months
Peak Rate (BO/D / MCF/D)	500 / 1250
b factor (oil / gas)	1.2 / 1.5
Initial Decline (oil / gas)	80% / 56%
Lateral Length	4,800
Type Well IRR %[2]	81.1%

Note: Production data normalized for 4,800' lateral length.
[1] Offset results based on Meramec wells drilled in the Updip Oil window of Kingfisher County since 2014.
[2] NYMEX Strip as of 8/3/2017. Does not include $300k PAD D&C facilities costs. Adjusted for transportation costs paid to KFM. Excludes $1.25 / bbl oil transportation costs.

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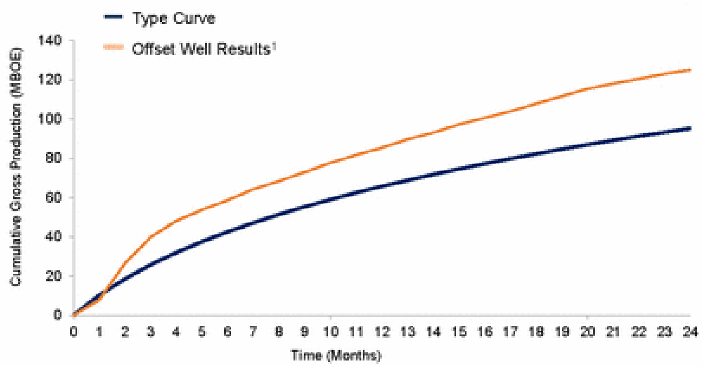
Oswego Type Curve

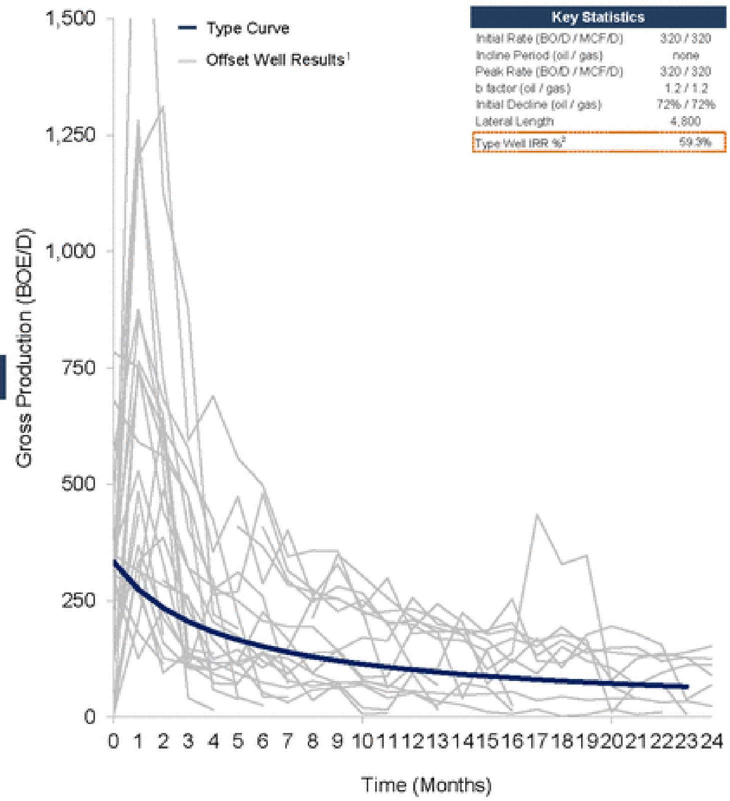
Summary

- Chesapeake, Chaparral, Cimarex, Gastar, and Longfellow are actively targeting the Oswego
- Other operators have future plans to develop the Oswego as a cheaper/shallower target
- IP rates are typically lower than Osage/Meramec wells, but decline rates are shallower
- With drilling and completion costs cheaper for the Oswego, well results do not have to be as strong as the headline STACK formations to make economic wells
- Average Type Curve Results
  - 233 MBOE 2-Stream EUR; 243 MBOE 3-Stream EUR
  - 200 MBO, 0.2 BCF residue, 15 MB NGL
- Type Curve assumes 16% Shrink and 75 bbl/MMcf NGL yield

Average Type Curve Cumulative Production



Average Type Curve



Key Statistics	
Initial Rate (BO/D / MCF/D)	320 / 320
Incline Period (oil / gas)	none
Peak Rate (BO/D / MCF/D)	320 / 320
b factor (oil / gas)	1.2 / 1.2
Initial Decline (oil / gas)	72% / 72%
Lateral Length	4,800
Type Well IRR %[2]	59.3%

Note: Production data normalized for 4,800' lateral length.
[1] Offset results based on Oswego wells drilled in the Updip Oil window of Kingfisher County since 2014.
[2] NYMEX Strip as of 8/3/2017. Does not include $300k PAD D&C facilities costs. Adjusted for transportation costs paid to KFM. Excludes $1.25 / bbl oil transportation costs.

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Substantial Inventory of Drilling Locations

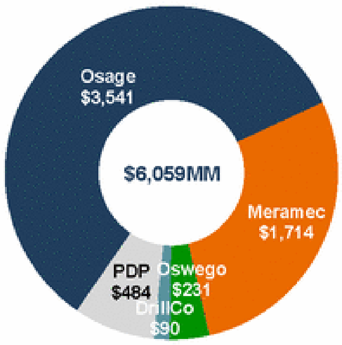
	Identified Drilling Locations		Prospective Drilling Locations				Combined
	Locations	Average Working Interest (%)	Other Formations Locations	Downspacing Locations	Total Locations	Average Working Interest (Including Downspacing Locations) (%)	Total Locations
Operated:							
Osage	1,196	72%	--	1,141	1,141	73%	2,337
Meramec	676	74%	--	676	676	74%	1,352
Oswego	203	75%	--	206	206	81%	409
Manning	--	--	168	--	168	75%	168
Other Formations	--	--	1,327	--	1,327	70%	1,327
Total Operated	2,075	73%	1,495	2,023	3,518	73%	5,593
Drilling Inventory (Years)	14.4	--	10.4	14.0	24.4	--	38.8
Other:							
Osage	1,252	15%	--	1,113	1,113	15%	2,365
Meramec	588	15%	--	596	596	15%	1,184
Oswego	281	13%	--	310	310	14%	591
Manning	--	--	316	--	316	14%	316
Other Formations	--	--	2,084	--	2,084	55%	2,084
Total Other	2,121	15%	2,400	2,019	4,419	28%	6,540
Total Gross Locations	4,196		3,895	4,042	7,937		12,133

Note: Does not include additional resource potential or undeveloped locations on ~20,000 net acres recently acquired in the Major County Acquisition.

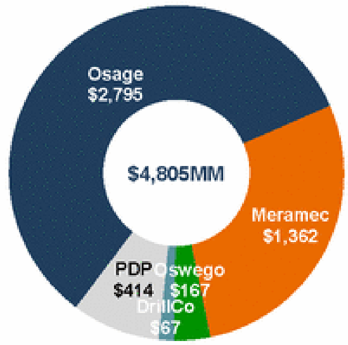
Substantial Resources

Volumes and PV-10 Value for 4,196 Primary Gross Identified Locations Only

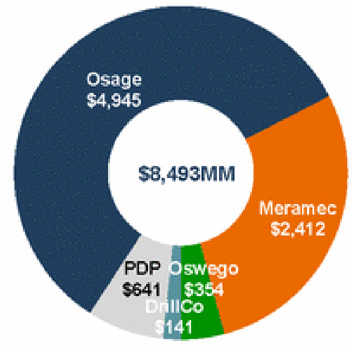
PV-10 at Research Consensus



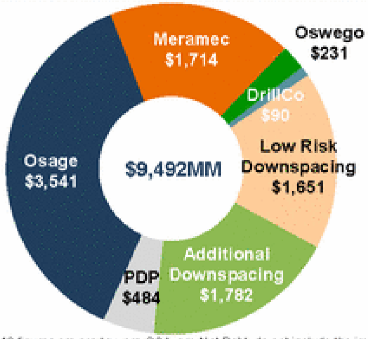
PV-10 at NYMEX[1]



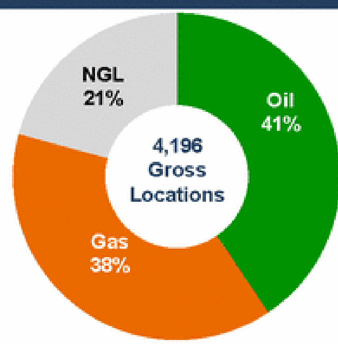
PV-10 at $70/$3.50



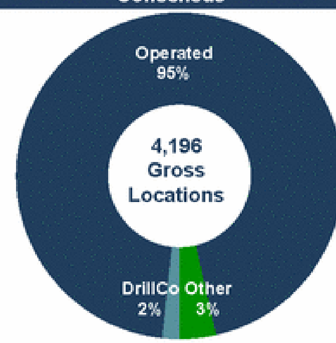
PV-10 at Research Consensus including Downspacing[2]



Identified Locations by Commodity



Base PV-10 by Operated at Research Consensus



Note: PV-10 figures are pre-tax, pre-G&A, pre-Net Debt, do not include the impact of hedges, and exclude $64mm Pipeline and facilities capital expenditures (PV-10). PV-10 figures as of 7/1/2017. Reflects Generation 2.0 Type Curve. Assumes Broker Consensus Price Deck (2017: $51.16/bbl / $3.16/mcf; 2018: $54.90/bbl / $3.14/mcf; 2019: $58.00/bbl / $3.05/mcf and held flat thereafter), unless otherwise noted. Does not include additional resource potential or undeveloped locations on ~20,000 net acres recently acquired in the Major County Acquisition. Adjusted for transportation costs paid to KFM. Excludes $1.25 / bbl oil transportation costs.

[1] NYMEX strip pricing as of 8/3/2017 close until 2021 and held flat thereafter. For 4,196 Primary Identified locations (for all but bottom left output that includes downspacing).

[2] Low Risk downspacing of Osage to 11 WPS (966 locations), Meramec to 5 WPS (318 locations), and Oswego to 4 WPS (516 locations). Additional downspacing of Osage to 15 WPS (1,288 locations) and Meramec to 8 WPS (954 locations).

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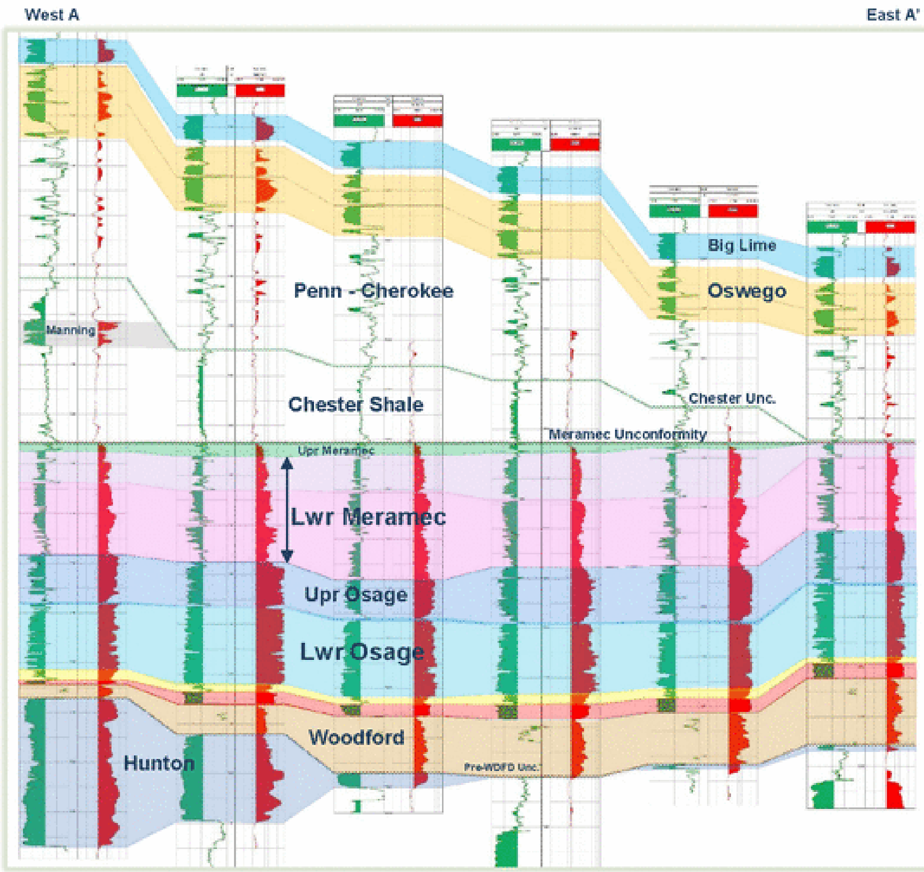
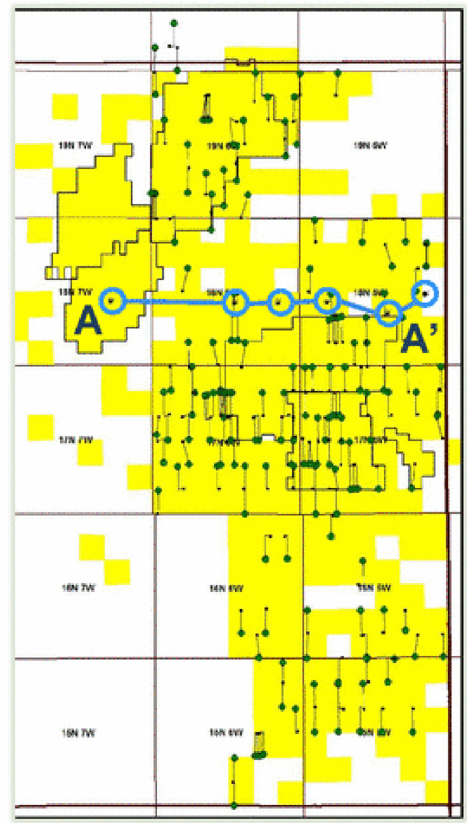
Stacked Pay: Oswego, Osage/Meramec Prominent

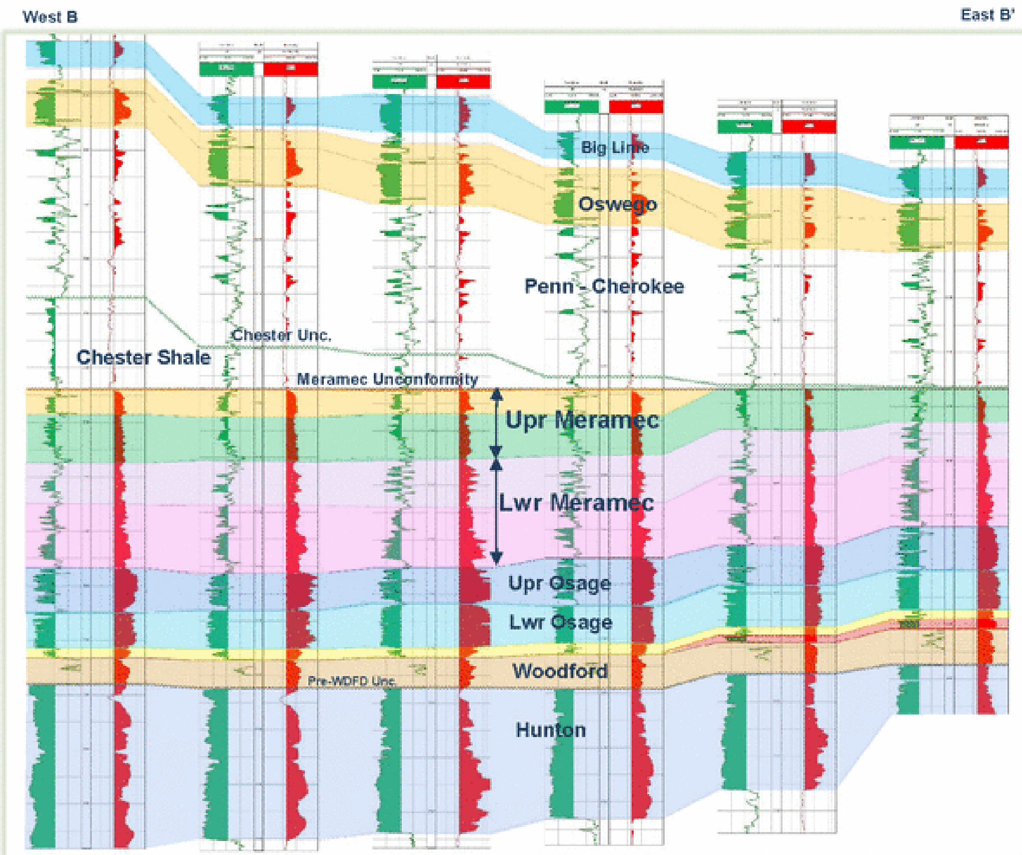
Oswego, Osage, and Meramec consistent east to west

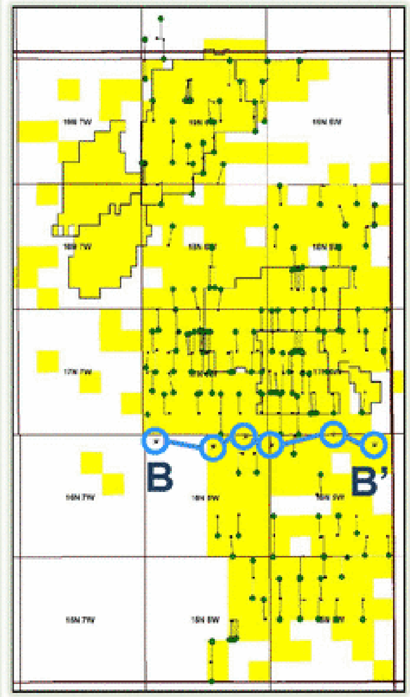




Significant Oswego, Osage/Meramec Section

Consistent thickness east to west





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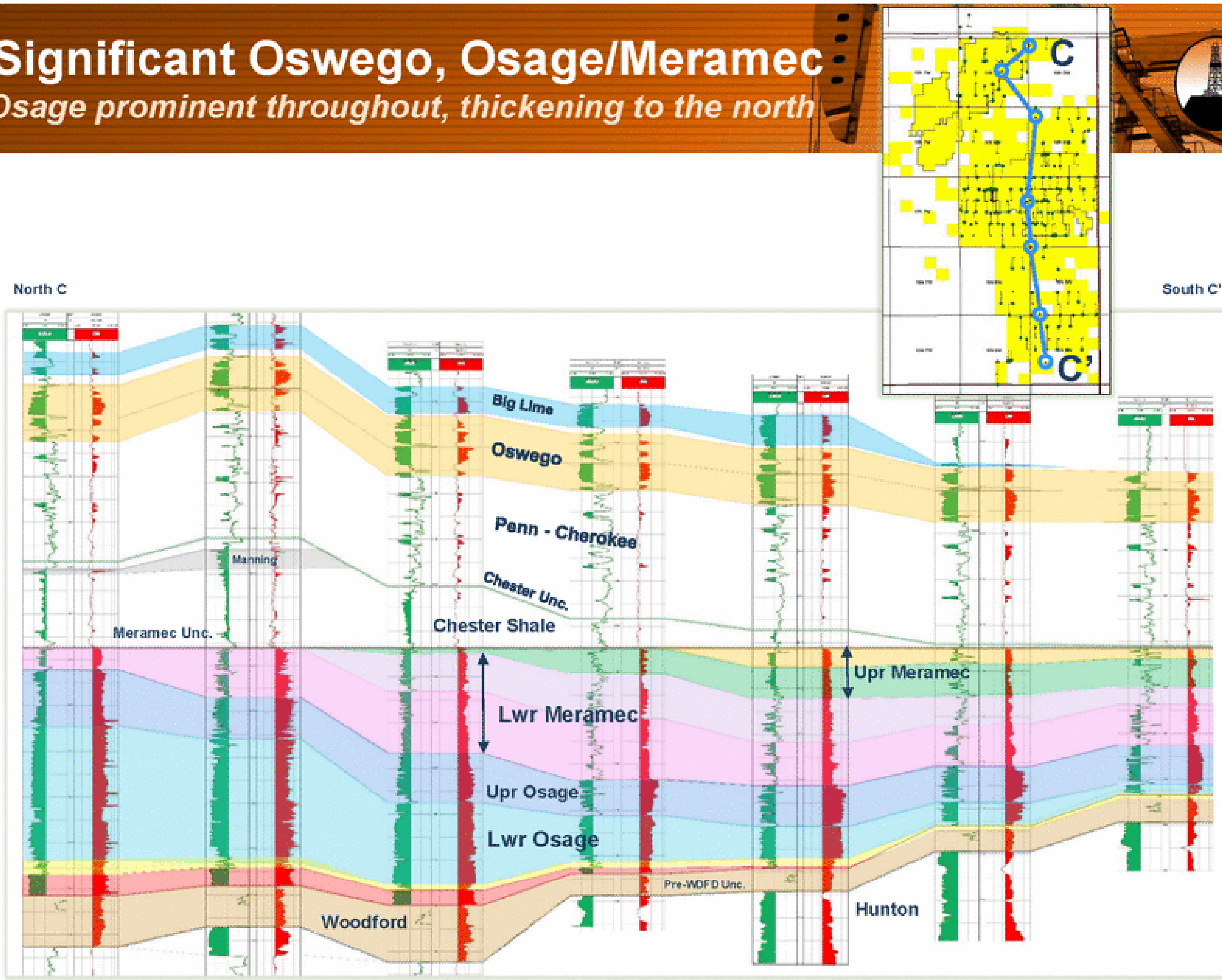
Significant Oswego, Osage/Meramec

Osage prominent throughout, thickening to the north



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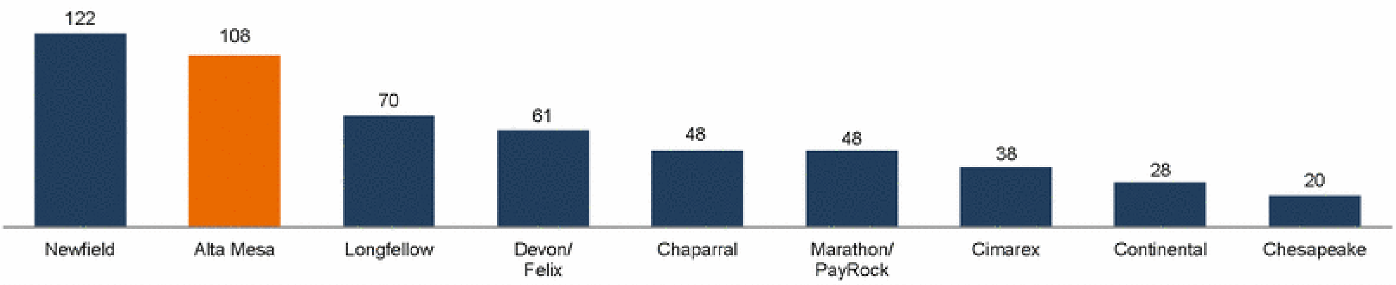
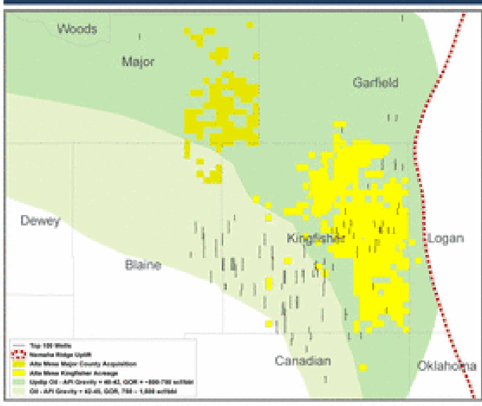
Top Cumulative Producing STACK Wells

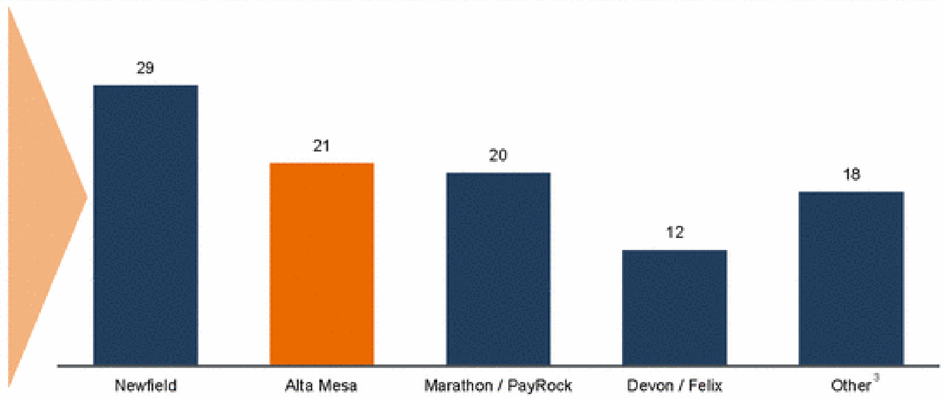
Alta Mesa wells among top producers

Cumulative Osage/Meramec STACK Producing Wells Drilled by Operator (2012-2016)[1]



Number of Top 100 Wells in the Oil and Updip Oil Windows by Operator, Measured by 60-Day Cumulative Oil Production[2]





Source: Company data, HPDI, IHS Herolds.
Note: Publicly disclosed Alta Mesa well / permits include those assigned to Oklahoma Energy Acquisitions LP and Hinkle Oil & Gas Inc.
[1] Based on publicly disclosed data for wells producing in Kingfisher, Blaine, Canadian, and S. Garfield counties. Excludes wells for which Woodford is primary target.
[2] Top Osage/Meramec wells (excluding Mississippian Lime) in Updip Oil and Oil window based on 60-Day Cumulative Oil Production (BBLS) per 1,000 Ft. of Lateral.
[3] Operators with 2 wells or fewer, except for Longfellow (8).

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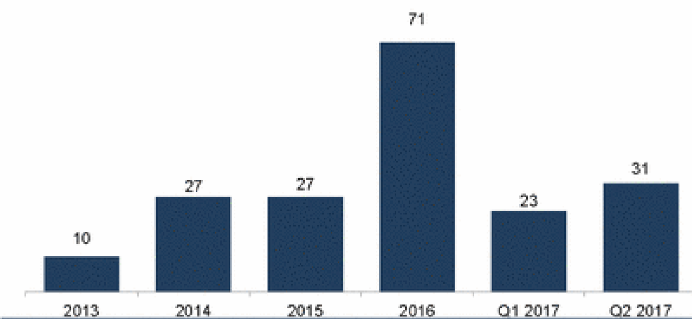
Alta Mesa Track Record of Growth

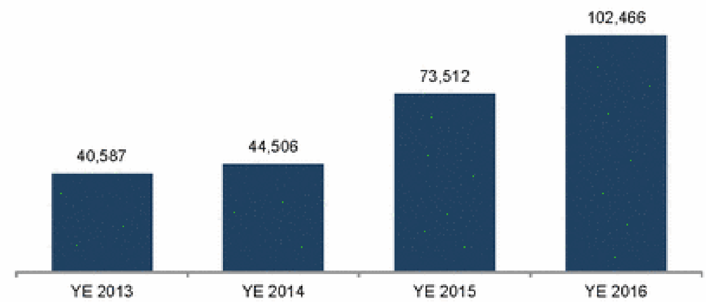
Consistent increases in production, reserves and acreage

Alta Mesa Operated Wells Drilled by Year

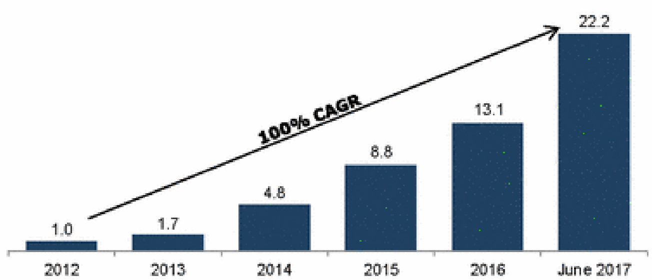
205 STACK wells drilled as of 8/10/17



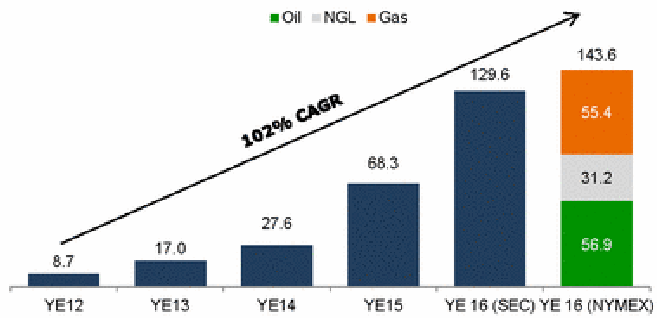
Alta Mesa Net STACK Acreage



Alta Mesa Total Net Production (MBOE/D)[1]



Alta Mesa Proved Reserves (MMBOE)[2,3]



Source: Company data, Public Filings, IHS Herolds, RigData.
[1] Inclusive of Net Production from Bayou City JV. 2012 and 2013 data reflects occurrence date and not accounting date LOS, due to the reasoning that occurrence date method incorporated a change in NGL accounting; whereas accounting date LOS does not.
[2] YE 2016 proved reserves as of 12/31/2016 close.
[3] YE12-15 proved reserves based on NYMEX pricing.

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DrillCo JV

Pivotal relationship with Bayou City Energy

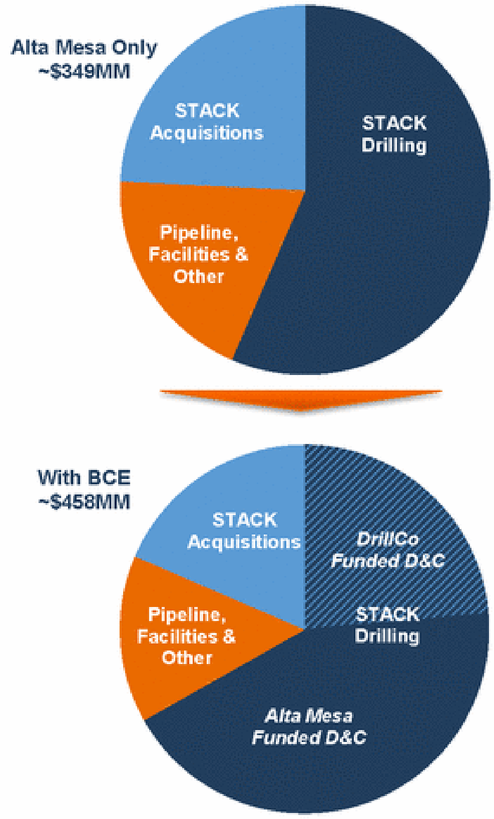
Parameters

- Entered into joint development agreement with Houston-based private equity firm, Bayou City Energy, in January 2016
- Bayou City Energy primarily targets small operators with current production and focuses on off-balance sheet structures
- DrillCo funds 100% D&C cost, capped at average of $3.2MM/well
- DrillCo gains 80% working interest in wellbore until 20-well tranche earns 15% IRR, 20% working interest until 25% IRR, then 12.5% working interest
- Specific wells pre-agreed for each tranche

Strengths for Alta Mesa

- Cash flow
- Grow reserves
- Continue resource definition
- Continue pace up learning curve(s)
- Capture, hold acreage
- Maintain people/crews

2017 Alta Mesa Estimated Capital Expenditures



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One Mile Laterals Optimum for Up-Dip STACK

Alta Mesa and other efficient operators adopt fit-for-purpose solutions

~5,000' laterals used for multi-faceted benefits: drilling, completions, production operations, land and legal

Consideration	Commentary
Spacing	One-mile lateral fits into a single section; two-mile laterals require establishing a "Multi-Unit spacing"
Drilling	Ability to use lower cost water-based muds and reduced time spent drilling helps to reduce drilling risk and control costs associated to high levels of natural fractures
Completions	Less proppant, fluids, and pumping time per well, more simplified design, lower friction while pumping all help to reduce costs of optimized completions
Mineral Owner Relations	Working with mineral owners across one-section (versus two-sections for longer laterals) allows for more seamless and confident development program planning

Alta Mesa Summary STACK Pro Forma Financials

($ in millions, unless specified)	Three Months Ended March 31, 2017	Three Months Ended December 31, 2016	Years Ended December 31, 2016	Years Ended December 31, 2015	Years Ended December 31, 2014
Production					
Oil (MBBLS)	942.0	989.1	3,057.2	2,006.1	1,071.6
Natural Gas (MMCF)	3,116.0	3,088.9	9,110.2	4,272.6	2,083.0
NGLs (MBBLS)	275.0	280.4	901.0	499.4	315.6
Total Production (MBOE)	1,736.3	1,784.3	5,476.6	3,217.6	1,734.4
Daily Production (BOE/D)	19,292.6	19,394.7	15,004.3	8,815.3	4,751.7
Statement of Operations					
Revenue	$63.6	$61.7	$166.4	$133.6	$117.3
Operating Expenses (Cash Items)	17.2	16.2	51.6	34.7	24.6
Exploration Costs (Cash Item)	5.0	7.5	17.2	9.8	11.8
Operating Expenses (Non-Cash)	20.2	23.8	63.3	80.3	29.4
General and Administrative[1]	9.7	8.7	40.5	37.9	68.4
Interest Expense[1]	12.3	1.4	43.4	62.5	55.8
Other Financial Data					
Adjusted EBITDAX[2]	$36.7	$36.8	$74.3	$61.0	$24.3
% Margin[2]	57.7%	59.6%	44.7%	45.7%	20.7%

Note: This historical pro forma financial information is unaudited and gives effect to (i) the expected disposition of Alta Mesa's non -STACK assets and operations prior to the closing of the business combination as if such transaction occurred on January 1, 2014 and (ii) the contribution to Alta Mesa of interests in 24 producing wells that were drilled under the BCE joint development agreement and purchased by High Mesa from BCE on December 31, 2016, as if such transaction occurred on January 1, 2016.
[1] General and administrative expense and interest expense for the total company.
[2] Adjusted EBITDAX is a Non-GAAP financial measure. See reconciliation to the nearest comparable GAAP measure in the appendix to this presentation.

Reconciliation of Adjusted EBITDAX to Net Income

($ in millions, unless specified)	Three Months Ended March 31, 2017	Three Months Ended December 31, 2016	Years Ended December 31, 2016	Years Ended December 31, 2015	Years Ended December 31, 2014
Net Income (Loss)	($0.8)	$4.1	($49.6)	($91.6)	($72.7)
Adjustments:					
Interest expense	12.3	1.4	43.4	62.5	55.8
Exploration expense	5.0	7.5	17.2	9.8	11.8
Depreciation, depletion and amortization expense	18.9	23.7	62.6	61.3	29.1
Impairment expense	1.2	0.0	0.4	18.8	0.0
Accretion expense	0.1	0.1	0.3	0.2	0.3
Adjusted EBITDAX[1]	**$36.7**	**$36.8**	**$74.3**	**$61.0**	**$24.3**

Note: This historical pro forma financial information is unaudited and gives effect to (i) the expected disposition of Alta Mesa's non -STACK assets and operations prior to the closing of the business combination as if such transaction occurred on January 1, 2014 and (ii) the contribution to Alta Mesa of interests in 24 producing wells that were drilled under the BCE joint development agreement and purchased by High Mesa from BCE on December 31, 2016, as if such transaction occurred on January 1, 2016.
[1] Does not include non-cash items - provision for income taxes, loss on extinguishment of debt, unrealized loss (gain) on oil and gas hedges and (gain)/loss on sale of assets.

EX-99.2 7 a17-20303_2ex99d2.htm EX-99.2

Exhibit 99.2

Alta Mesa Holdings, LP

August 17, 2017

CORPORATE PARTICIPANTS

James Hackett, *Chief Executive Officer, Silver Run II*

Harlan Chappelle, *President and Chief Executive Officer, Alta Mesa Holdings, LP*

Michael McCabe, *Vice President and Chief Financial Officer, Alta Mesa Holdings, LP*

PRESENTATION

James Hackett:

Hello, everyone. I'm Jim Hackett. Hal Chappelle and I are very excited to be here today to talk about a compelling investment opportunity. I'll walk through an introduction of the company, as well as a brief overview of the transaction. Hal will come in and speak about the Upstream and Midstream assets. Then he'll turn it over to Mike McCabe, the CFO, to talk about the financial overview. Finally, I'll finish with some comments about valuation and timeline going forward. Hal?

Harlan Chappelle:

Thanks, Jim, and hello. We cannot be more excited than to work with Jim Hackett and Silver Run II to build upon the value we've created and the progress that we've made in the STACK. We look forward to walking through this material with you today. Jim?

James Hackett:

Thanks, Hal. First, we'll talk about the introduction. When we went out to look for targets for Silver Run II, we had laid out investment criteria that are shown on Slide 5. Both individually as an Upstream and Midstream Company, and collectively as an integrated platform, this transaction satisfies those criteria.

Turning to Slide 6, this is the first pure-play publicly traded STACK company, which is, I think, very exciting for the investor community. It has everything we desired in terms of highly contiguous oil weighted acreage, 120,000 acres in the core of the STACK, at very attractive breakeven prices, as you can see on the top of Slide 6. We have 4,000-plus primary gross locations based on what we are currently doing. As a drilling and a completion strategy, we have over 12,000 possible locations from down spacing, as well as additional zone penetration. Hal will go through more of that with you in a minute.

We have here a very seasoned cohesive, very experienced team in terms of what they've been doing for over a decade. This is unlike almost any other private company you can name. They have drilled over 200 horizontal STACK wells, they've survived several commodity cycles, they have industry-leading growth potential at approximately 130%. By virtue of combining the Midstream and Upstream, we have both flow assurance for constraining periods of time on all three liquids that we produce. We also produce better net backs because of that position, and, importantly, the purpose-built system that

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accommodates Alta Mesa also accommodates third-party volumes. We have 300,000 gross acres dedicated to that system in addition to the 120,000 acres that Alta Mesa has committed to this system.

We have, I think, tremendous advantages in terms of strategic positioning for consolidation down the road and a future opportunity to restructure the Midstream business into an MLP IPO, which I'll cover later in the presentation.

Finally, Mike McCabe will talk more about the financial strength and flexibility, and we're very excited about the position we've put ourselves in with regard to the balance sheet.

Turning to Slide 7, in the middle of that slide you'll see the multiples that we anticipate for the firm value relative to the EBITDAs for 2018 and 2019. A little later in the presentation I'll show you competitive data that indicates these are highly attractive multiples for each of the individual businesses. Importantly, to Investors, the existing owners of Alta Mesa will roll 100% of their equity position in Alta Mesa into this combination and are on the same side of the table as all of us, as well as the other owners of KFM are retaining significant equity stakes in the combined entity going forward. Riverstone and its affiliates will invest at least $600 million of additional cash into the business, and the anticipated closing is the fourth quarter of 2017. We'll talk more about that timeline in a minute.

On Slide 8, we have the Transaction Summary we've arrayed for you in the upper left portion the Sources and Uses statement. In the middle on the top is the implied firm value at 3.836 billion dollars. And on the post transaction ownership is on the upper right portion. It's the legacy Alta Mesa owners you can see in the orange there at 37%, Riverstone in Green at 22%, the rollover equity for the KFM owners is 14%. And then the Legacy Silver Run II owners are at 27%. So there is a major commitment here from the sellers to the future of the organization. The bottom is a proforma organizational chart. You can see that Hal and I are joined at the top. I will be Executive Chairman, he'll be the CEO. I'll also report to Hal running the Midstream business as COO because we'll be losing that team after a transition period and we'll be building a team there to replace them. And then Mike Ellis will remain as COO of the Upstream business. Mike will be stepping down as Chairman of the combined Company.

Harlan Chappelle:

Thanks, Jim. I'll be going over the Upstream and Midstream assets of this Enterprise. Let's start on Page 10. As you can see on the map on the right, we've got a highly blocked up contiguous acreage position in the up-dip oil window of the STACK.

We have a durable asset. Not only do we have a resource that has three zones that we have de-risked and delineated, but we have a complete petroleum system of over a billion barrels of resource in the area. This is a redevelopment of the Sooner Trend field that we get to be a part of. Not only that, but we have infrastructure—water, gas, oil, salt water disposal—and so we have an opportunity to be very systematic in development of this acreage.

We've got a team that has been executing on this for quite a number of years together, as Jim indicated earlier. We now have a multi-rig program we've averaged six rigs through the bulk of this year, and we can scale up with confidence because we have the discipline processes, both on the front end of drilling in terms of getting the land position together, in terms of defining where we want to drill, but then also in executing on that.

We have over 200 wells that we've drilled here and we've demonstrated the value and we have confidence in the upside. As an illustration of that, at the end of the second quarter, we had drilled on the order of 200 wells. Of those, over 160 were on production, and of that number, about 114 had sufficient

production history to give us confidence that at the end of this year, our year-end reserves will reflect better than 650,000 BOE. Since our average lateral length is just under 4,700 feet, that equates to about 140 BOE per lateral foot. That's an important metric as we look and try to compare what this asset is to others in the basin, which very typically denominate their results in terms of a normalized 10,000-foot of lateral.

Let's move on to Page 11. I talked about the team. The character of this team is we have major league players with relevant experience who have worked together for a considerable amount of time. We have capabilities in all assets of the operation and we've got disciplined processes. Among those processes are the public company processes that are necessary, the disciplines, if you will, the accountability of being a public company. For the last almost seven years, we've been a public reporter because of the bonds that we have issued, and then we also issued new bonds last year. So, we're very comfortable with that and we're confident that we can execute in all aspects of this Enterprise.

How did we get here? Page 12 is a history, if you will, in pictures. Mike Ellis founded our Company in 1987, and early in the 1990s he was acquiring various pieces of acreage. In 1992 he was able to start the acquisition of large production units in the eastern side of Kingfisher County, which Conoco, Texaco, and Exxon had been operating but were exiting North America at the time in favor of other places. We entered in 1992. Through the next couple of decades there's been a stewardship that's occurred. In the mid-2000s we began a program while we were producing about a thousand barrels a day. We went through the process of drilling about 27 vertical wells so that we could delineate other zones, either shallower or deeper, that could be prospective and could be the target of additional development, whether horizontal or vertical at the time. Consistently, as we drilled those wells, we found that the Osage and the Meramec were prospective and productive in a commercial way.

By the time we got into this decade, in 2012, we had a high level of confidence that we could begin horizontal drilling and in 2012 we spud our first two wells. By the end of 2013, we had 13 wells that had flowed back and we had gone through two generations of well designs, starting with 12 stages of fracks, to 18 stages, and from one completion configuration to a more advanced one. We learned a lot during that period, such that by 2014 we had confidence that this was a scalable program and so we began a process of acquiring additional acreage all around our initial footprint. You can see that by the end of 2015 we had acquired over 70,000 net acres to our interest.

By 2016, we had hit our stride in terms of having a de-risked and delineated acreage position, in our view, and we had disciplines in place and processes that allowed us to scale and operate in a development mode.

Let's move on to Page 13 so we can look at basically the economics of this. I talked about how many wells we've drilled, our expectations of those, and our confidence in those. On the upper left-hand part of this page you can see the breakevens. We're below $30 per barrel, and that's to achieve a 15% internal rate of return in terms of breakeven price. On the upper right-hand side you can see the individual well returns, depending on which price deck that you might want to use, that generate about 85% internal rate return, even at a NYMEX strip.

Now, other STACK operators have achieved good well head returns here as well, and so there's been an enormous investment in drilling capital in the basin. This, in turn, as well as our development, became an ideal backdrop for the growth of the Kingfisher Midstream operation. To date, as you can see on the lower left-hand side of the page, Kingfisher Midstream has acreage dedications of about 300,000 gross acres with a line of sight to over 500,000 gross acres. Now, this also has provided the opportunity for a substantial growth in third-party volumes which Kingfisher Midstream has been able to begin and continue to grow.

Finally, when it comes to the importance of Kingfisher Midstream to Alta Mesa, it's simply a strategic competitive advantage for us. We've got a purpose-built system that allows us to operate confidently in a multi-well development mode, we've got efficient processing, and we have access that's assured to the interstate markets during a time where there could be periodic constraints due to the large-scale growth in the area.

How does this all build up? Let's summarize the overview here. On Slide 14, you can see the NAV build-up to about $7 billion based on 4,200 identified gross drilling locations that we'll describe. It's broken up so that we can distinctly illustrate to you the Upstream and the Midstream value components, and you can see this here on the page.

On the right side of the page you can see the growth opportunities that we see from additional down spacing and other opportunities that Kingfisher could have through additional third-party development.

Finally, we did make an acquisition—about a month ago we closed on it—and we have not included any of the locations that we believe could be drilled there in our tallies that show up on these pages, so we simply show you on the right-hand side of the page that that represents some upside.

Let's move on and focus down now on the Upstream a little bit more. First on Page 16, simply, we're in a neighborhood where there's a lot of activity going on, vigorous drilling around us, and even within our footprint, targeting both Oswego and the Mississippian-age,

Osage and Meramec.

On Page 17, you get a maybe even better sense of how well-established in a short period of time this play has gotten. Not too many years ago, what you see on this map in Northwestern Canadian County, as listed as the Cana-Woodford, was really the biggest extend of activity. In the time since then, a lot of drilling has occurred by Devon, Continental, Newfield, now Marathon, and certainly by Alta Mesa and some of the other private companies in the area, so it's a large density of wells here. We've only drilled 200 wells, though, so far, and there's a lot of room to run.

Let's move on to Slide 18. This shows the progress in mean well results that we've been able to achieve in a very short period of time by drilling intensely and purposely across about a 300 square mile area here in Easter Kingfisher County. We focused on a couple of keys. The first is isolation between stages. Our first well design was a sliding sleeve configuration and we found that to be very ineffective and we had very good science behind our assessment of those wells. We've gone to a plug-and-perf, open-hole design, and now we have high confidence in a very effective frack job. The next key is a landing. We look for mechanical rock properties and reservoir properties that give us the best opportunity to find the most attractive reservoir and get a very effective frack job off.

Then, finally, the way that we steer our wells is very, very important. We have a dedicated team of geo-steerers that assure to the best of their ability that we stay within the zone that we're targeting, and that's given us a big part of the reason that we have been able to get consistent well results.

You see here on this page that we've gone through generations, beginning with 12 stages, going on to 18, 24, and then 32 to 36, depending on how long the lateral is, and our next-generation design is likely to be 100-foot frack stage spacing, meaning on the order of 45 to 48 stages for a one-mile, lateral, if you will, 4,800-foot lateral would be the typical target.

On Page 19, there's some more detail here for you that shows you first the progress of well completions on the upper left; second, very importantly, the consistent production characteristics of our wells. We're in an area with hundreds of vertical wells that give us solid data upon which we can base our projections and our understanding of the Meramec and Osage system, as well as the Oswego above that. In the Meramec and Osage, as shown here on the lower left, we have early flow back, which is almost entirely

oil in terms of the hydrocarbons—would be flowing back water from the frack, obviously—and then the GOR climbs over time. These production characteristics, with the oil waiting being biased to the early years of the well, give us good economics as well.

Let's move on to Page 20 where—let's talk about our cost structure in some more detail. Relative to what our competitors in the area have published is shown here. We have a fairly low cost per well. First, we have geologic advantages. We're shallow, we're naturally fractured, we have a simple well design. Second, we have a legacy infrastructure for water supply, water disposal, access to well sites, access to services. All those things combined together to give us a very good drilling time, and when we couple that with consistent deployment of rigs over a period of time, we can get efficiencies of process that we're taking advantage of today.

We think there's upside in our drilling and completion costs in terms of the opportunity to cut our costs because we're going into more of the development mode and we'll be drilling multi-well pads where there are shared services, there's less mobilization time associated with that, and the other advantages of scale.

Let's move on with just a little bit more specificity on the cost structure. On Page 21, this shows the effects of our costs. First on the top, future development cost per PUD barrel, is shown here as very low, and we compare it to what others have published. Probably the most important measure on this page is the recycle ratio. You can see how we measure up compared to our competitors and the peers that we think are relevant, as well as showing you what that additional benefit that will come to us from having an integrated midstream operation as part of the enterprise.

Finally, on the lower right you can see where LOE per barrel ranks. Now, we see some tremendous upside in our ability to cut costs, our LOE costs as well, from the same points that I made earlier about F&D costs. The bottom line of our cost structure here is we've got durable operations, low F&D, high capital efficiency, and low lease operating expenses, with the opportunity to cut those costs with scale, very much a factor of robust infrastructure that we have. This goes back to one of the first points I made. We have highly contiguous acreage here where we can scale with confidence and manage across a larger acreage footprint than simply one drilling unit at a time.

Now, let's talk about results. I describe them in terms of the type curve we expected at the end of last year, and I showed you other results earlier, but on Page 22, one of the things we think is very important to communicate is how pervasive and extensive over this

large area in the up-dip oil window, we have good well results. This table on the right-hand side of the page is meant to help you with that and it shows you a number of wells. We highlight some key wells here as well. While we don't have audited reserves for our newer wells, we did think it relevant to give you some information in terms of the IP 30s of some recent wells, and so that's also listed on this page.

Let's move on to Page 23 now. Those good well results, the very, very good cost structure, our confidence in the geology and our ability to execute, all boil down to our ability to take on the development program that's shown here in a base case, if you will.

The graphic on the left side shows our base development plan. We've performed 11 spacing tests across our footprint. Continental, Newfield, Devon, Marathon have all described their spacing tests in the STACK as well. We have 11 spacing tests, 7 of which are on flow back, some of which for an extended period of time. These have given us insights that give us the confidence in a base case shown here. In this 550- foot plus or minus interval of the Meramec Osage, there would be three benches, each bench would have four wells landed in them, so spacing of about what you might call 160 acres or 1,500 feet between the laterals.

Ultimately, we seek to maximize discounted cash flow and we believe that this is going to be achieved with a combination of either further down spacing and/or optimized completion techniques where we can get more of this at a more valuable basis.

How do we put this in perspective? One of the things that's helpful—there's on the other order of 33 to 35 million barrels of oil in place in the Meramec and Osage, on average within a drilling unit across—or a section, a square mile—across our acreage position. This based development plan in the Osage Meramec recovers about 8% of that oil in place. That should be a good measure and a comparator to some of the other resource plays. It also gives us confidence that that combination of optimized well completions and/or additional wells—in other words, down spacing—will be profitable to undertake.

Finally, we show the Oswego as a zone in which we have immense confidence of the development capability here. We show only two wells per drilling unit—in other words, a section square-mile—although there are other operators within our footprint who are developing the Oswego with four wells per section.

The bigger picture really here is shown on Page 24. I described this earlier when I talked about the 1,100-foot thick section that's a major part of this petroleum system that is the Sooner Trend field area. Each of these zones that are listed here are commercially productive from vertical wells within our footprint, with the one exception of the Chester Shale, which we believe could be a horizontal target but which has not been, to our knowledge, a successful vertical target in time. We tried to provide you with a grid here. It shows you how many wells we think per section could be prospective in these various zones.

Finally, this log that's on the left-hand side of the graphic is a well log from a continuous section from a log in the northern part of our acreage, and it actually has some of the Manning Limestone that does show here. That's important since we are flowing back our first Manning horizontal after having over 200 Manning vertical wells that have produced.

The bottom line on this slide is it's a petroleum system that works. There's a focus on an 1,100-foot thick multi-STACK pay area. The three zones that we have the most confidence in are the Osage, Meramec, and Oswego at this point in time, but we see every one of these zones as a potential target.

This could be described in terms of the drilling inventory on page 25 to which I referred earlier. On the left side of this page you can see how the approximate forty-two hundred locations were identified in Meramec, Osage and Oswego. The middle of the page reflects the potential for down spacing and/or increased effectiveness of completions. The right hand side is our way of showing you the potential for further development of additional zones that we believe are prospective within our acreage footprint. Now we can define the upstream opportunity in terms of this drilling inventory because of our demonstrated ability to execute. Turning now to slide 26, we illustrate our growth in net acreage, net production and proved reserves since we began horizontal development of our STACK position. Please note the map on the right side of this slide shows a recent acquisition in Major and Blaine counties. Our goal in acquisitions is to control good acreage of scale. Summarizing, the growth we've achieved gives us confidence in the continued execution and expected growth that we project.

Turning to Page 27, in the broader STACK area there is significant acreage that could be consolidated by operators such as ourselves. We believe that this combination with Jim positions us to compete effectively for good opportunities. We have the advantage of a solid operations base, a scalable team with years of experience, a low cost structure and the expertise to determine value in this area.

Now moving on to Page 29 to discuss the midstream assets. Kingfisher Midstream is an important part of our operation today and will be increasingly so in the combined enterprise. For want of capital, we

would have built this ourselves a few years ago due to the growing functional constraints and inherent inefficiencies of older legacy processing and gathering, as well as concerns that this basin may experience, periodic and near-term limitations to residue gas takeaway, particularly to interstate markets. Kingfisher affords us and other nearby operators with a purpose-filled system to handle the larger volumes associated with multiple wells sold back from single pads and to do so in a more efficient processing system giving us lower shrink, higher yields and better economics. As I alluded a moment ago, Kingfisher gives us flow assurance. It is physically positioned to connect directly to interstate markets by Panhandle Eastern to access Midwest and Gulf Coast markets as well as OGT for access to western interstate markets. Importantly, we have firm transport rights on both of these interstate systems. Which also makes us more competitive as we consider potential acquisitions. Since commissioning just a year ago, Kingfisher has systematically grown its customer base to include several other operators besides Alta Mesa, and we believe this will be an increasingly important and valuable part of the midstream business. Let me now turn this over for a moment to Jim so he can discuss the broader vision for our midstream operations. Jim…

James Hackett:

On slide 30, we just are trying to portray here the valuation arbitrage that exists between the margin that is in KFM within the E&P business as a combined entity, and then eventually as an MLP Entity restructured out of the E&P entity where we control the GP interest. And what is very familiar to all of you is that the multiple step up that you get from the upstream median at 7 ½X to midstream medians of 13.7X EBITDA and eventually to the GP interest at 25.3X EBITDA.

On the lower left we've just taken an illustrative EBITDA, call it 1.0 dollars and just showing that step up in terms of the multiples applied to that investment or that value — that implied value — on those various multiples. And so we take the KFM EBITDA projection in 2019, estimated at $318 million, and we roll that over to the right under the illustrative midstream value creation, and you have the value of that EBITDA in the margin in the upstream of $2.4 billion increasing by $1.96 billion with the MLP issuance, which is currently anticipated in the first part of 2019, to create an MLP value fully distributed at $4.35 billion. And then eventually several years later issuing a GP into a public entity and getting an uplift of some $924 million and that amounts to a total of $5.275 billion for the value of that total margin. Comparing that against the $2.39 billion that is within the combined entity at the beginning, you can see the uplift represents nearly $3 billion, and that is approximately 80% of the combined purchase price of these entities at $3.8 billion, essentially paying for a large portion of the merger.

Harlan Chappelle:

Thanks, Jim. On Slide 31 you can see the existing infrastructure. Kingfisher Midstream today has 60 million cubic feet a day of processing in the center of our acreage. It's currently undergoing an expansion of 200 million a day for a total of 260 million a day of processing. That'll be done by the end of this year. There's about 250 miles of low-pressure gathering line and about 75 miles of high-pressure gathering line here. We have significant deal compression and there's crude storage in the middle of the field here.

On Page 32, there's even more detail for you to refer to here on natural gas, NGLs, and crude aspects of this Kingfisher Midstream enterprise. You can see, in terms of takeaway on the gas side, we have 120 a day of FT on Panhandle Eastern and 50 million a day of FT on OGT. That 50 million a day is going to increase to 125 million a day in June of next year. For NGLs there's about 41,000 barrels of capacity on the Chisholm line. For crude, today we're trucking our crude from the central gathering system to Cushing, but we have several opportunities to interconnect to pipelines direct into Cushing, which gives us additional advantages in terms of both net back price and in terms of reliability.

Finally on Page 33, Kingfisher Midstream is well-positioned to gather and process increasing volumes from the play as it moves to the West. Notably, as we move to the West in this play, gas volumes do increase.

Let me turn it over now to Mike McCabe, our CFO, as he goes through the finances of this new enterprise.

Mike McCabe:

Turning to Page 35, obviously this would become a major de-leveraging event for Alta Mesa Resources. It will create a zero-net debt on our balance sheet and provide us with excellent pro forma liquidity to execute the development plan in the STACK and Kingfisher County. Our intent is to manage to a 1.0X debt to EBITDA tax ratio with 1.5-2.0X guardrails on a situational basis. This will allow Alta Mesa Resources to have positive cash flow from Operations as early as 2019 and to continue to maintain a simplified balance sheet with our revolver and senior unsecured bonds. Turning to Page 36, our 2017 Capex budget is $458 million which includes $108 million of funds from Bayou City Drilling JV. KFM will complete the expansion of its facility to $260 million a day capacity which is included in their $120 million capex budget remaining for 2017. And we will expect to grow from currently at 6 rigs to 10 rigs by the end of 2018. Also, our hedges are summarized at the bottom of Page 36. We will continue to be disciplined, but active, in our hedge program and protecting our revenues going forward.

Turning to Page 38, which is a summary of financial objectives for the future, we are expecting a 3X growth in net daily production to approximately 65K BOE per day in 2019, and a 5X growth in EBITDAX over the same period. And again we will go positive free cash flow from operations in 2019 while we create and maintain sufficient liquidity to fund our development plan as summarized in the middle section of the bottom bar on Page 38.

James Hackett:

On Slide 39, we have the first of two valuation pages. This is just for the upstream portion of the merger. And you can see in the upper left the firm value is a multiple of 2018 EBITDA, and of course, it looks very attractive relative to the peer group. And then 2019 gets even better and that's because the growth rate in the lower right portion of this slide. And then if you look in the bottom left portion all we've done here is try to give you comparables for the Anadarko Basin for acquisitions on a net acreage basis.

Turning to Page 40, we've done the same for KFM. If you look at the Midstream multiples of 2018 and 2019 EBITDA, the firm value for this transaction is highly attractive relative to those entities on the lower left portion of the graph. Then when you take the combined companies, both Upstream and Midstream, you can see that that growth rate, not surprisingly, captures both of these slides in terms of combining the two, and matches what we had told you earlier in the presentation.

On Slide 41, we are showing the anticipated transaction timeline.

On Page 42, just to summarize, what we see in this opportunity in front of us for a pure-play STACK company is a world-class asset. We've got great rocks, we've got great technical tools, great people, and a great track record with high growth in front of us. We've put together a Midstream business that provides us defensive and offensive capabilities in terms of both internally growing our business, as well

as consolidating those around us, and a potential financial restructuring of that Midstream business, that I've spoken to you earlier about, is incredibly compelling in terms of the upside for our Investors.

We'll have financial strength and flexibility to execute the business plan through this current down cycle, and we'll still end up being positive cash flow-wise in 2019.

With that, I'll end the pro forma presentation. Hal and I will look forward to seeing all of you in the near future. We couldn't be more excited about this opportunity in front of us. Thank you.

PX 289

From: "Hackett, Jim" <JHackett@riverstonellc.com>
Sent: Thu, 13 Dec 2018 15:38:15 +0000 (UTC)
To: "will@bayoucityenergy.com" <will@bayoucityenergy.com>
Cc: "Limbacher, Randy" <RLimbacher@riverstonellc.com>; "Campbell, John"<JCampbell@riverstonellc.com>
Subject: FW: AMR D&C Thoughts

Will,
Thanks for this thoughtful note to those on the distribution. We have discussed testing an open-hole completion for months, but never got the completion team to test one, since we were too busy chasing unrealistic production forecasts.
Look forward to future dialogue on this issue.
Jim

From: Limbacher, Randy
Sent: Thursday, December 13, 2018 9:18 AM
To: William McMullen <will@bayoucityenergy.com>
Cc: Hackett, Jim <JHackett@riverstonellc.com>; Campbell, John <JCampbell@riverstonellc.com>; Castiglione, Mark <MCastiglione@riverstonellc.com>
Subject: RE: AMR D&C Thoughts

Good morning Will,

Thanks for sharing this with us. We look forward to discussing on Friday.

From our conversations we would agree that an intense focus on optimizing capital efficiency would be one very important step to restoring the companies health. This would be one area of early focus. I will share this analysis with John and we will be happy to address our thoughts which I think you will find are very consistent with your own.

Randy

From: William McMullen [mailto:will@bayoucityenergy.com]
Sent: Thursday, December 13, 2018 8:53 AM
To: Hackett, Jim; Limbacher, Randy
Cc: Mark Stoner; Andrew Koehler
Subject: AMR D&C Thoughts

Jim, Randy,

Thanks very much for sharing the financial models and other analyses prepared by AMR and Meridian at this important inflection point for the business. It's evident that the challenge collectively in front of us as stakeholders is significant and will not be easily solved. We do, however, hold firm the belief that when facing such difficulties an open mind to contrarian perspectives can provide the path to overcoming a seemingly insurmountable obstacle. In this regard, I'd like to offer you a brief perspective on what we believe to be the primary hurdle to value creation at AMR – its cost structure. And for purposes of this email, I'd like to focus on our drilling and completion ticket.

As you know, our industry, and AMH/AMR as a typical example thereof, has become enamored with the pursuit of large IPs and EURs through the relentless application of technological advancement and increased completion intensity. The same trend that has unlocked extensive new oil & gas resources for development has, in some cases, also been the driving force behind diminishing investment returns and the destruction of capital. BCE, with the perspective of being partnered with (or indeed internal to) AMH for several years now has closely watched the evolution of well and completion design (Generations 1 through 3+) undertaken by AMH in the STACK. At least one thing is clear, even when normalizing for the shift to infill development – capital efficiency has declined, as more expensive wells (relative to the pervading service cost environment of the time) have not resulted in uplifted oil recoveries. See below table:

Gen.	Years	Well Count	Oil EUR	Gas EUR	Mboe	AFE D&C	AFE Oil F&D	Actual D&C	Actual Oil F&D	Frac Stages
1	2013	6	106.0	712.5	227.8	$3,674,750	$33.71	$4,160,513	$36.17	12.0
1.5	2013	5	191.8	1,551.4	451.4	$3,698,820	$19.91	$4,618,670	$22.96	16.2
2	2014 - 2016	42	209.7	1,533.1	461.5	$3,702,820	$17.65	$3,940,558	$18.79	22.4
2.5	2016 - Q1 2018	136	178.7	1,232.0	383.4	$3,674,648	$20.48	$4,074,472	$22.67	32.0
2.3	2018	24	147.3	1,025.2	318.2	$3,884,909	$26.37	$3,677,891	$24.97	29.5
3	2018	4	156.3	1,011.6	324.8	$3,970,833	$25.41	$4,362,796	$28.21	38.8

Includes some incomplete cost totals

Reflect pre-downturn service cost levels

*Only includes wells in sections with 4 or fewer wells as a proxy for avoiding infill wells

We understand our method of analysis here is imperfect, but much the same conclusion was put forth on slide 19 of Meridian's review presentation:

"…no increase in well performance is observed from Generation 1.5 to 2.5."

This reality, along with the following others…

- E&P companies and assets garner favor (and premium valuations) largely on the basis of free cash flow generation;
- BCE has had success in pushing well costs lower in other portions of its portfolio, while maintaining reserve recoveries (also in the Mississippian formation in Central OK) – as you know, we have a drilling partnership with Chaparral and an extensive platform in the Miss Lime with Mach Resources;
- Overhanging uncertainty regarding sustained commodity price levels (and therefore preservation of an acceptable operating margin, absent a strict adherence to a lean cost structure)

…inclines us to question if AMR would be better off fundamentally prioritizing low well (and operating and overhead) costs first and emphasizing reserve enhancement/replacement and production IPs second.

Using the models shared from AMR, and a 3+1 rig capital pace, we looked at a scenario wherein AMR manages to reduce its average D&C well cost to $2.25mm, for 140 MBO EUR per well, and compared 2019 and 2020 financial metrics to a base case of $3.9mm D&C and 200 MBO EUR wells. Both scenarios assume a 30% G&A reduction, and a 20% LOE reduction vs. the default 200 MBO Case levels presented in the recent AMR board deck.

200 MBO / $3.9MM D&C

	2019	2020
Avg. Net Daily Production	34.2	38.8
EBITDAX	$ 274,369	$ 261,250
CAPEX	$ 309,277	$ 268,220
FCF	$ (66,565)	$ (63,642)
YE Liquidity	$ 184,599	$ 100,958
YE Leverage	2.7x	3.1x

140 MBO / $2.25MM D&C

	2019	2020
Avg. Net Daily Production	35.4	33.4
EBITDAX	$ 257,818	$ 212,369
CAPEX	$ 194,173	$ 170,138
FCF	$ 13,734	$ (7,525)
YE Liquidity	$ 276,549	$ 272,024
YE Leverage	2.4x	3.0x

Admittedly, the results are crudely arrived at but our directionally accurate and our financially grounded – thus, it has stoked our curiosity around the conceivable positive implications such an approach could have for AMR. Further, we noted in the Meridian/VSO analysis that the various EUR range type curves generally shared a similar IP rate assumption, and primarily deviated in terms of decline profile. If that reflects reality, then the economic difference between a 140 MBO and 200 MBO well lies mostly beyond the first 12 to 18 months of production and is therefore of less importance to our company managing for the financial realities of the here and now over the next few years. Said differently, if the lower 140 MBO EUR curve is simply pivoted downward from the 200 MBO EUR curve IP rates instead of shifted downward across the curve, a heavily reduced completion design would even be further advantaged. Our thoughts here were meant to begin a directional conversation with you vs. being overly precise in our analysis

without complete information. To that end..

We'd be interested to see a detailed cost component analysis of AMR's well design and an attempt at rebuilding an AFE targeting a materially lower well cost (<$2.5mm). What could the company drill and complete a Generation 1.5 well for today? Could such a design result in a 120+ MBO EUR assuming ~5 wells per section? Could further cost reductions be achieved on the drilling side by utilizing lower spec rigs? With less intense wells mean we could put more wells in a section thus improving NAV considerations while maintaining capital efficiency on single well economics? The rapid growth trajectory once set out for AMR may no longer be attainable – but perhaps there is a path to achieving a robust free cash flow generating business with a materially reduced cost structure.

Lastly, I'm attaching a few slides from our last Mach BOD meeting. We have over 300 HZ producing wells on our ~250,000 acreage footprint and since BCE took over ownership in April 2018, we have drilled/completed ~40 wells running a 3-rig program in the Miss Lime interval. Our average well cost of ~$1.9mm gives us a 12 to 14 stage frac well over a 1-mile lateral (we spend ~$1.1mm-$1.3mm on the drilling and ~$650k on completions). We have overwhelmingly observed up here (as well as in most single-well economic analyses) that D&C costs are the LARGEST driver of single-well IRRs (not commodity prices, not reserves, not LOE). And thus, we have deliberately erred on the side of reducing D&C in lieu of perhaps EUR and even EBITDA. The upside has been that we've been a significant FCF generator.

We believe significant FCF is what is needed at AMR and thus why we wanted to share a few of our experiences and perspectives with you all. I believe this conversation is worth expanding on as well as is a renewed focus on LOE and G&A reductions.

To that end, at any time, if you'd like to hear perspectives on this directly from Tom Ward and our Mach team, we'd be delighted to share and have a get together in Houston.
Look forward to Friday,

Will

William W. McMullen | Founder & Managing Partner
Bayou City Energy |
1201 Louisiana Street, Suite 3308 | Houston | TX | 77002
O: 713.400.8210 | [redacted] | E: will@bayoucityenergy.com

PX 290

From: Tim Turner [tturner@AltaMesa.net]
on behalf of Tim Turner <tturner@AltaMesa.net> [tturner@AltaMesa.net]
Sent: 8/18/2017 3:28:29 PM
To: Tamara Alsarraf [talsarraf@AltaMesa.net]; Jackson, James R [james.r.jackson@citi.com]
CC: Michael A. McCabe [mmccabe@AltaMesa.net]
Subject: RE: RE: RE:

Other levers are WI (I think we've already increased, but we have some control over where we drill) and rig count. Either way, you increase capex and overspend which is what we opted to curb.

-----Original Message-----
From: Tamara Alsarraf
Sent: Friday, August 18, 2017 3:04 PM
To: Jackson, James R <james.r.jackson@citi.com>; Tim Turner <tturner@AltaMesa.net>
Cc: Michael A. McCabe <mmccabe@AltaMesa.net>
Subject: RE: RE: RE:

Also, we're completing ~17 wells per month in 2018 (92% of them are AMH vs BCE). The model assumes 4 frac crews and at an average of 17 completions per month, it is technically better than best case scenario of (4.3 stages/crew/day, and 34 stages/well).

-----Original Message-----
From: Tamara Alsarraf
Sent: Friday, August 18, 2017 2:56 PM
To: 'Jackson, James R ' <james.r.jackson@citi.com>; Tim Turner <tturner@AltaMesa.net>
Cc: Michael A. McCabe <mmccabe@AltaMesa.net>
Subject: RE: RE: RE:

We're doing that already. My two cents is that this model is already pretty aggressive. We rarely ever come in higher than forecasted on production (due to higher shut-ins, etc). Currently, we have 47 scheduled completions between Sep and Dec, and we have prioritized AMH completions over BCE to boost 2018 EBITDAX.

-----Original Message-----
From: Jackson, James R [mailto:james.r.jackson@citi.com]
Sent: Friday, August 18, 2017 2:39 PM
To: Tim Turner <tturner@AltaMesa.net>
Cc: Tamara Alsarraf <talsarraf@AltaMesa.net>; Michael A. McCabe <mmccabe@AltaMesa.net>
Subject: RE: RE: RE:

What other levers do we have to goose the 18 forecast besides rig count? Do we have the ability to bring the DUCs on line faster?

James R. Jackson, CFA
[redacted]

-----Original Message-----
From: Tim Turner [mailto:tturner@AltaMesa.net]
Sent: Friday, August 18, 2017 2:38 PM
To: Jackson, James R [ICG-CIB]
Cc: Tamara Alsarraf; Michael A. McCabe
Subject: Re: RE: RE:

Gas forecast wasn't much different than 2.0.

Tim

> On Aug 18, 2017, at 2:35 PM, Jackson, James R <james.r.jackson@citi.com> wrote:
>
> Thanks Tamara.
>
> Any idea how much I'd take up the KFM component with that increase?
>
> James R. Jackson, CFA
[redacted]
>

Exhibit
CP- 0191
3/23/2023
Turner

>
> -----Original Message-----
> From: Tamara Alsarraf [mailto:talsarraf@AltaMesa.net]
> Sent: Friday, August 18, 2017 12:15 PM
> To: Tim Turner; Jackson, James R [ICG-CIB]
> Cc: Michael A. McCabe
> Subject: RE: RE:
>
> I'm coming up with 2018 EBITDAX of $374MM using the Gen 2.5 type curve.
>
> Gen 2.5
> 2018 - $374MM
> 2019 - $743MM
> 2020 - $1,082MM
>
> Gen 2.0
> 2018 - $358MM
> 2019 - $700MM
> 2020 - $1,368MM
>
> -----Original Message-----
> From: Tim Turner
> Sent: Friday, August 18, 2017 10:23 AM
> To: Jackson, James R <james.r.jackson@citi.com>; Tamara Alsarraf <talsarraf@AltaMesa.net>
> Cc: Michael A. McCabe <mmccabe@AltaMesa.net>
> Subject: RE: RE:
>
> Sorry...ringer turned off. Try again.
>
> -----Original Message-----
> From: Jackson, James R [mailto:james.r.jackson@citi.com]
> Sent: Friday, August 18, 2017 10:19 AM
> To: Tim Turner <tturner@AltaMesa.net>; Tamara Alsarraf <talsarraf@AltaMesa.net>
> Cc: Michael A. McCabe <mmccabe@AltaMesa.net>
> Subject: RE: RE:
>
> Have tried you a couple times. When is a good time to connect?
>
> James R. Jackson, CFA
[redacted]
>
> -----Original Message-----
> From: Tim Turner [mailto:tturner@AltaMesa.net]
> Sent: Friday, August 18, 2017 7:58 AM
> To: Tamara Alsarraf
> Cc: Michael A. McCabe; Jackson, James R [ICG-CIB]
> Subject: RE:
>
> James,
>
> Please provide some color on purpose. Gen 2.5, as represented by YE16 reserves, was about 300 MBO. With more data and more wells, our mean Gen 2.5 well has dropped to about 280 MBO at midyear.
>
> -----Original Message-----
> From: Tamara Alsarraf
> Sent: Friday, August 18, 2017 7:31 AM
> To: Tim Turner <tturner@AltaMesa.net>
> Cc: Michael A. McCabe <mmccabe@AltaMesa.net>; Jackson, James R <james.r.jackson@citi.com>
> Subject: Re:
>
> Tim - can you provide me with the gen 2.5 type curve file (that looks like the mint color tabs labeled oil, gas, ngls, in my model)?
>
> Sent from my iPhone
>
>> On Aug 18, 2017, at 7:27 AM, Jackson, James R <james.r.jackson@citi.com> wrote:
>>
>> Tamara -
>>
>> If you take your model that shows $543mm of 18 ebitda and run a gen 2.5 type curve through production, what does ebitda look like for 18 and 19?

>>
>> Sent from my BlackBerry 10 smartphone.
>

PX 291

From: "Wang, Kevin" <KWang@riverstonellc.com>
Sent: Thu, 24 Aug 2017 17:57:03 +0000 (UTC)
To: "Karian, Drew" <dkarian@riverstonellc.com>
Cc: "Dodds Williamson, Chelsea" <cwilliamson@riverstonellc.com>
Subject: Background of the Business Combination
Attachments: Background to Transaction v08.24.2017.docx;Silver_Run_Aquisition_Corp_Proxy.pdf

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Drew,

Please see attached for a rough skeleton of the Background to the Business Combination section for the proxy. Right now it is just a shell and some items are bracketed (e.g. exact dates, attendees, meeting discussion points).

Let me know if this is a good starting point or if we need to dig a bit more.

Regards,
Kevin

Exhibit
CP- 0245
3/28/2023
Wang

Silver Run II is a blank check company formed in Delaware on [November 16, 2016], for the purpose of effecting a merger, capital stock exchange, asset acquisition, stock purchase, reorganization or similar business combination with one or more businesses. The business combination is the result of an extensive search for a potential transaction utilizing the global network and investing and operating experience of our management team, board of directors, and external advisors and those of Riverstone.

The following is a description of the background of the negotiations of the Contribution Agreement, business combination and related transactions by Silver Run II, [ ], and [transaction entities].

Prior to the consummation of our IPO, neither Silver Run II, nor anyone on its behalf, contacted any prospective target business or had any substantive discussions, formal or otherwise, with respect to a transaction with Silver Run II.

From the date of our IPO through the end of [July 2017], Silver Run began to search for business combination candidates. As part of the search process, representatives of Silver Run II and Riverstone contacted and were contacted by a number of individuals and entities with respect to business combination opportunities and engaged with several possible target businesses in discussions with respect to potential transactions.

During that period, James Hackett, the Chairman and Chief Executive Officer of Silver Run II, and representatives of Riverstone, including Stephen Coats, Robert Tichio, Olivia Wassenaar, Drew Karian and Chelsea Williamson:

- developed a list of approximately [175] potential corporate and asset exploration and production opportunities, including [AMR], located in Silver Run II's targeted areas— [the Bakken, Eagle Ford, Montney, Permian and Powder River Basin shale plays];
- considered and conducted analysis of approximately [30] potential acquisition targets; and
- engaged in discussions with representatives of approximately [20] potential acquisition targets.

Paragraph to be edited to reflect SRII. [Apart from CRP, Silver Run did not conduct or engage in material discussions, due diligence or negotiations with respect to any alternative target opportunity. The decision not to pursue the alternative acquisition targets was generally the result of one or more of (i) Mr. Papa and Riverstone's determination that the assets were not of sufficient quality, (ii) a seller's unwillingness to engage in a transaction during the low-price phase of the commodity cycle, (iii) a difference in valuation expectations between Mr. Papa and Riverstone, on the one hand, and a seller, on the other hand, (iv) a seller's unwillingness to engage with Silver Run given the timing and uncertainty of closing due to the requirement for Silver Run stockholder approval and/or (v) Mr. Papa and Riverstone's determination that the complexity and uncertainty involved (such as a corporate carve-out) caused the opportunity to be too unlikely to warrant the expenditure of considerable resources.]

In late 2016, Kingfisher retained JPM and Barclays to explore a potential sale through a targeted process, [solely/mainly] focused on select, public MLPs.

March [ ], 2017 – BCE and Alta Mesa management approached Jim Hackett and Riverstone following the closing of the Silver Run II IPO to discuss a potential transaction.

April 3, 2017 – meeting between Hal and Jim at Alta Mesa's office in Houston.

On April 9, 2017, to facilitate the discussions, Riverstone and Alta Mesa signed a confidentiality agreement.

On April 10, 2017, to facilitate discussions, Riverstone and Kingfisher signed a confidentiality agreement.

On April 10, 2017, meeting with Alta Mesa management team in Houston at Alta Mesa's office. Riverstone attendees included [Jim, David & Pierre, Chelsea, Robert, Drew, Neil]. Detailed review of the Company's assets.

April 15, 2017 – Riverstone engaged representatives of TPH [Chad Michael and Jeff Knupp] to advise on a potential transaction with Alta Mesa.

April 20, 2017, meeting between ARM and their financial advisor JPM (Jonathan Sloan) and Riverstone (Robert, Baran, Olivia, Drew, Chelsea, Neil).

April 25. 2017 – TPH presented its view on Alta Mesa's assets and the underlying geology to Riverstone in New York.

May 4, 2017 – Investment Committee of Riverstone Fund VI "heads-up" meeting approves non-binding bids for both Kingfisher and Alta Mesa.

May 4, 2017 – Silver Run II board call.

[Shortly after May 4] – a representative of Riverstone communicated a non-binding bid of $1.3 billion for Kingfisher. [Around same time], Riverstone communicated a non-binding bid of $2.7 billion to Alta Mesa.

[A few days later] – Alta Mesa and Kingfisher each communicated that they viewed their respective Riverstone bid as below value expectations.

On May 31, 2017, meeting with ARM at ARM's Houston office. Purpose to discuss the upstream economics of Kingfisher's acreage dedications. Riverstone attendees include Jim, Drew, Baran?, Staudinger?, John Campbell, Mark Castiglione, Randy Limbacher.

June 7, 2017 – Investment Committee of Riverstone Fund VI meeting for both Alta Mesa and Kingfisher. Approved revised bids of 3.0 billion for Alta Mesa and $1.6 billion for Kingfisher.

June 8, 2017 – due diligence meeting at Alta Mesa's office. Riverstone attendees included [Drew, Randy and Meridian team, Rock Oil team, Jim]. [Believe that a tentative follow-up meeting on the next day June 9 was not needed]

[Early to mid June] – Riverstone communicated a revised bid of $3.0 billion for Alta Mesa and $1.6 billion for Kingfisher.

[Agreement on purchase price, various discussions on key deal terms]

July [12], 2017 – Jim meets Hal at Alta Mesa's office. Due to crude price declines in June and the corresponding poor performance of oil and gas companies, Jim submitted a revised proposal with a $2.5 billion valuation for Alta Mesa. The proposal also featured a $500 million earnout based on stock price. Riverstone did not revise its offer for Kingfisher as the midstream business is more insulated from commodity price fluctuations.

[Series of negotiations but ultimate agreement on revised price]

July 18, 2017 – Silver Run II board meeting. Update on transaction progress.

July 19, 2017 – TPH presents to Silver Run II board.

July 21, 2017 – Silver Run II board meeting.

July 25, 2017 – Citi began reaching out to existing investors in Silver Run II to market a $500 million PIPE for a portion of the cash sources to close the contemplated transaction with Alta Mesa and Kingfisher. Through August 4, 2017, Alta Mesa management and Jim Hackett, along with representatives from Citi, met with investors to explain the investment merits of the proposed transaction. Mixed feedback from the PIPE marketing process: some investors were enthusiastic while others voiced concerns related to the valuation, geologic risk, and general macroeconomic factors affecting the oil and gas industry broadly. [Think we probably need to disclose the PIPE marketing but perhaps we can spin it in a positive light]

August 4, 2017 – Silver Run II board meeting / call.

August 7, 2017 [possibly Aug 8] – Riverstone communicated a revised proposal to Alta Mesa and Kingfisher which featured a $2.1 billion valuation for Alta Mesa and a $1.2 billion valuation for Kingfisher. In addition, the proposal shifted more of Kingfisher's consideration into rolled equity. Riverstone also offered to commit an additional $200 million in a new forward purchase agreement. [Probably don't need to mention the increased earnout here] The proposal was meant to lower the cash needs for transaction so that a PIPE was no longer required. The proposal also had the benefit of addressing valuation concerns from some investors throughout the PIPE marketing process.

On August 9, 2017, Alta Mesa (Hal Chapelle) and Kingfisher (Zach Lee) put forth a counterproposal to Jim Hackett which valued Alta Mesa at $2.3 billion and Kingfisher at $1.45 billion.

On August 10, 2017, Jim Hackett communicated to Hal Chappelle and Zach Lee a revised proposal with an aggregate purchase price of $3.55 billion without specifying the valuation split between Alta Mesa and Kingfisher. The proposal also stipulated a greater equity roll from Kingfisher in order to achieve conservative leverage levels at transaction close.

Acceptance of Riverstone's proposal. Drafting of deal docs up until deal announcement.

August 11, 2017 – Silver Run II board meeting / call.

August 14, 2017 – [Hold for Silver Run II board update – not sure if this happened]

Stock. We will have the right to cause the removal of the Series A Director from our board of directors immediately upon redemption of the Series A Preferred Stock as described above.

Background of the Business Combination

Silver Run is a blank check company formed in Delaware on November 4, 2015, for the purpose of effecting a merger, capital stock exchange, asset acquisition, stock purchase, reorganization or similar business combination with one or more businesses. The business combination is the result of an extensive search for a potential transaction utilizing the global network and investing and operating experience of our management team, board of directors, and external advisors and those of Riverstone. The following is a description of the background of the negotiations of the Contribution Agreement, business combination and related transactions by Silver Run, NewCo and CRP.

Prior to the consummation of our IPO, neither Silver Run, nor anyone on its behalf, contacted any prospective target business or had any substantive discussions, formal or otherwise, with respect to a transaction with Silver Run.

From the date of our IPO through the end of June 2016, Silver Run began to search for business combination candidates. As part of the search process, representatives of Silver Run and Riverstone contacted and were contacted by a number of individuals and entities with respect to business combination opportunities and engaged with several possible target businesses in discussions with respect to potential transactions.

During that period, Mark Papa, the Chairman and Chief Executive Officer of Silver Run, and representatives of Riverstone, including Stephen Coats, Robert Tichio, M. Cliff Ryan, John Staudinger and Austin Winger:

- developed a list of approximately 175 potential corporate and asset exploration and production opportunities, including CRP, located in Silver Run's targeted areas—the Bakken, Eagle Ford, Montney, Permian and Powder River Basin shale plays;
- considered and conducted analysis of approximately 30 potential acquisition targets; and
- engaged in discussions with representatives of approximately 20 potential acquisition targets.

Apart from CRP, Silver Run did not conduct or engage in material discussions, due diligence or negotiations with respect to any alternative target opportunity. The decision not to pursue the alternative acquisition targets was generally the result of one or more of (i) Mr. Papa and Riverstone's determination that the assets were not of sufficient quality, (ii) a seller's unwillingness to engage in a transaction during the low-price phase of the commodity cycle, (iii) a difference in valuation expectations between Mr. Papa and Riverstone, on the one hand, and a seller, on the other hand, (iv) a seller's unwillingness to engage with Silver Run given the timing and uncertainty of closing due to the requirement for Silver Run stockholder approval and/or (v) Mr. Papa and Riverstone's determination that the complexity and uncertainty involved (such as a corporate carve-out) caused the opportunity to be too unlikely to warrant the expenditure of considerable resources.

On April 5, 2016, Mr. Cliff Ryan of Riverstone called Ward Polzin, Chief Executive Officer of CRP, to propose a discussion regarding a potential transaction involving CRP and Silver Run.

On April 13, 2016, to facilitate the discussions, Riverstone and CRP signed a confidentiality agreement.

On April 19, 2016, Mr. Papa and Mr. Cliff Ryan met with Mr. Polzin at Riverstone's office in Houston. Mr. Polzin provided an overview of CRP, including its corporate history, assets and future development plans. Mr. Papa expressed an interest in learning more about CRP and exploring the

possibility of a transaction with CRP involving Riverstone and Silver Run. Mr. Polzin reciprocated that interest.

On May 5, 2016, Mr. Papa, along with representatives of Riverstone, met with CRP's management team in CRP's office in Denver. Mr. Polzin and the other members of CRP's management team provided detailed information on CRP's corporate history, acreage, production history, well performance, financial results and future development plans, and agreed to make available additional diligence information upon request.

Between May 5, 2016 and June 6, 2016, Mr. Papa and representatives of Riverstone conducted their initial due diligence based on the information provided by CRP and other publicly available sources. Riverstone also engaged Latham & Watkins LLP ("Latham") as counsel to Riverstone. Based on Mr. Papa's and Riverstone's review of the diligence materials, Mr. Papa and Riverstone determined that (i) CRP was attractively positioned in the oil-rich core of the Southern Delaware Basin, (ii) CRP had a large horizontal drilling inventory across multiple pay zones, (iii) CRP's acreage had been delineated across multiple zones, (iv) CRP had proven horizontal drilling expertise and technical acumen in the Delaware Basin and (v) CRP had a high degree of operational control over its assets, and, on the basis of the foregoing, concluded that CRP was a highly attractive target for Silver Run. Over the same timeframe, representatives of NGP Energy Capital Management, L.L.C. ("NGP"), CRP's sponsor, expressed that CRP had been and would continue preparing for an initial public offering, but that they appreciated the benefits of a transaction involving Silver Run and were interested in pursuing the idea further.

On June 6, 2016, Mr. Tichio sent NGP a non-binding letter agreement that outlined the basic terms for a potential transaction where Silver Run would acquire CRP and the existing owners of CRP would receive Silver Run shares and up to $200,000,000 in cash, at such existing owners' election, in lieu of additional shares. As the initial basis for negotiations, the letter agreement proposed a $1,300,000,000 enterprise value on a cash-free, debt-free basis, and was subject to confirmatory due diligence and certain other conditions. The letter agreement also requested an exclusivity period. The terms of the letter agreement were determined jointly by Mr. Papa and Riverstone. Mr. Papa and Riverstone analyzed the net present value of estimates of future after-tax cash flows, precedent merger and acquisition transaction metrics, and public company trading metrics prepared internally by Riverstone in determining that $1,300,000,000 was a reasonable enterprise value for the basis of beginning negotiations with NGP.

On June 9, 2016, representatives of Riverstone and NGP held a call to discuss the details of the non-binding letter agreement and the timeline and mechanics of consummating a transaction between Silver Run and CRP. Mr. Papa did not participate in the discussion.

On June 13, 2016, Mr. Papa held a call with representatives of NGP to follow-up on the June 9, 2016 call. The representatives of NGP communicated that NGP was still evaluating the non-binding letter agreement.

On June 17, 2016, Mr. Papa met with representatives of NGP at Riverstone's office in Houston. NGP communicated to Mr. Papa that it would not be pursuing a transaction with Silver Run given the timing and uncertainty of closing due to the requirement for a vote of the Silver Run stockholders to approve the transaction but would instead target launching CRP's IPO in mid-July 2016.

On June 21, 2016, Mr. Tichio of Riverstone and representatives of NGP held a call to discuss the potential of an all-cash acquisition of CRP by funds controlled by Riverstone, rather than Silver Run, but which would include the flexibility for the funds controlled by Riverstone to assign its rights and obligations under the Contribution Agreement to Silver Run. The change in acquirer was intended to address the timing and uncertainty of closing concerns NGP raised during the June 17, 2016 meeting. Riverstone concluded that (i) CRP was an attractive investment opportunity, (ii) the funds controlled

by Riverstone should pursue the acquisition of CRP in lieu of Silver Run and irrespective of whether Silver Run ultimately participated in the acquisition and (iii) there were substantial benefits to the funds controlled by Riverstone by assigning its rights and obligations under the Contribution Agreement to Silver Run. Among other benefits, investing in CRP indirectly through Silver Run would reduce the exposure of Riverstone Global Energy and Power Fund VI ("Riverstone Fund VI") to a more desirable level, enhance liquidity as the funds would be invested in a public company and provide CRP the benefit of Mr. Papa's involvement on a day-to-day basis going forward and enhanced access to capital markets to execute its growth plan. NGP expressed its willingness to consider an all-cash acquisition by funds controlled by Riverstone, but that the proposed $1,300,000,000 enterprise value was insufficient.

On June 23, 2016, Riverstone and NGP held a call during which Mr. Tichio of Riverstone submitted a verbal non-binding proposal from funds controlled by Riverstone to acquire CRP in an all-cash transaction at a $1,500,000,000 enterprise value on a cash-free, debt-free basis, subject to confirmatory due diligence and certain other conditions. Mr. Tichio also stated his preference that CRP would have minimal or no debt outstanding after closing. During the call, NGP expressed its desire to retain the senior management of CRP for a potential new venture, if a transaction was consummated, following a reasonable transition period. NGP also expressed its desire to retain a portion of its equity interest in CRP. Finally, representatives of NGP and Riverstone discussed Mr. Papa's anticipated role within CRP following an acquisition by Riverstone. In the event the funds controlled by Riverstone assigned its rights and obligations under the Contribution Agreement to Silver Run, Riverstone expected Mr. Papa to be the day-to-day CEO of CRP. If those rights and obligations were not assigned to Silver Run, Mr. Papa's role had not been determined.

On June 24, 2016, representatives of Riverstone and NGP held a call to discuss certain elements of the June 23, 2016 non-binding proposal. Mr. Papa did not participate in the discussion. The representatives of NGP stated that CRP at that time planned to launch its IPO on July 7, 2016, but that a number of strategic buyers were evaluating an acquisition of CRP. Furthermore, the representatives of NGP stated that CRP was prepared to forgo the IPO and end discussions with other potential buyers if it signed an agreement reflecting (i) a $1,575,000,000 enterprise valuation for CRP on a cash-free, debt-free basis, (ii) an option for NGP and the other existing owners of CRP to retain a $200,000,000 stake in CRP, (iii) that the existing CRP senior management team would provide three months of transition services commencing on signing of definitive documentation and not be solicited by CRP to remain with CRP following such transition service period, (iv) a deposit of $157,500,000 million payable at the time of signing of definitive documentation and (v) that definitive documentation would be signed prior to the proposed July 7, 2016 CRP IPO launch.

Later that day, Mr. Tichio of Riverstone and representatives of NGP agreed in principle to the above material terms, with the exception that the transition service period was extended to four months commencing on signing of definitive documentation, under which the funds controlled by Riverstone would acquire CRP, subject to agreement on definitive documentation, confirmatory due diligence and the requisite approvals from the Investment Committee of Riverstone Fund VI and the Board of Riverstone Energy Limited ("REL").

On June 27, 2016, Vinson & Elkins LLP ("V&E") sent a draft Contribution Agreement to representatives of Latham, which, consistent with the terms agreed to in principle by Riverstone and NGP on June 24, provided for the acquisition by NewCo of a controlling interest in CRP. The draft Contribution Agreement indicated that the right of NewCo to assign its rights and obligations under the Contribution Agreement to Silver Run and the provisions relating thereto would be discussed between the parties.

On June 28, 2016, representatives of Latham and V&E discussed, among other things, the provisions relating to NewCo's right to assign its rights and obligations under the Contribution

Agreement to Silver Run, as well as NGP's desire to utilize an "up-C" structure whereby NGP would have the ability, following the closing of the potential transaction, to exchange its minority equity position in CRP for shares of Class A Common Stock in Silver Run. Additionally, between June 28, 2016 and July 1, 2016, representatives of Latham and V&E discussed various other issues, including Riverstone's desire to restrict the ability of the Centennial Contributors and members of CRP's senior management from acquiring oil and gas properties adjacent to the properties of CRP as of the Closing and the ability of the parties to negotiate the terms of any limited liability company agreement of CRP, registration rights agreement and other ancillary documents in the event that NewCo assigned its rights and obligations under the Contribution Agreement to Silver Run.

On June 29, 2016, Latham sent a revised draft of the Contribution Agreement to representatives of V&E that addressed, among other things, the ability of NewCo to assign its rights and obligations under the Contribution Agreement to Silver Run.

On June 29, 2016, the Investment Committee of Riverstone Fund VI held a meeting to discuss the potential acquisition of CRP by Riverstone Fund VI and REL. In addition, the Investment Committee discussed the potential participation of Silver Run after the execution of definitive documents, with a focus on (i) the mechanics of Riverstone Fund VI investing in CRP through Silver Run, (ii) the amount Riverstone Fund VI would invest in Silver Run to ensure Silver Run had the capital to consummate the transaction, (iii) the expected benefits Silver Run's involvement would bring to Riverstone Fund VI and CRP, (iv) the timeline, mechanics and uncertainty of Silver Run's stockholder vote and (v) the ability of Silver Run's stockholders to opt to redeem their stock for cash in the event the transaction were approved and the resulting uncertainty in Silver Run's ability to have the cash required to fund the transaction. With respect to the occurrence of redemptions, the Investment Committee discussed the possibility of Riverstone Fund VI purchasing a numbers of shares equal to the number of shares redeemed by Silver Run's public stockholders. The Investment Committee considered that this would ensure Silver Run would have the required capital to close the transaction and likely be well received by Silver Run investors. The transaction (but not the assignment) as presented was approved pending notification of the final terms and conditions.

On July 1, 2016, V&E sent a revised draft of the Contribution Agreement to representatives of Latham. The draft contemplated a six-month non-compete provision that would generally restrict CRD and any Senior Management Entity from acquiring or evaluating the acquisition of oil and gas properties adjacent to the properties of CRP as of the Closing. Further, the draft contemplated that the Centennial Contributors could elect to receive all cash consideration in the event the parties were unable to agree on final forms of a limited liability company agreement of CRP, registration rights agreement and other ancillary documents prior to a specified date.

Between July 1, 2016 and July 6, 2016, the parties continued to negotiate and finalize the Contribution Agreement, including the provisions discussed above. In addition, during such time, Riverstone Fund VI agreed to guarantee NewCo's monetary obligations under the Contribution Agreement in an amount not exceeding $1,217,500,000. Also during this time, Latham completed confirmatory legal, tax, regulatory, benefits and land/title due diligence to the satisfaction of Riverstone.

On July 5, 2016, the Investment Committee of Riverstone Fund VI was notified of and approved the final terms and conditions of the transaction to acquire CRP. Also on July 5, 2016, the REL Board of Directors held a special telephonic meeting to discuss the contemplated acquisition of CRP with and without the potential participation of Silver Run and approved the transaction as presented.

On July 6, 2016, NewCo and the Centennial Contributors executed the Contribution Agreement pursuant to which NewCo agreed to acquire a controlling interest in CRP and had the right, but not the obligation, to assign its right to purchase the interest in CRP to Silver Run, subject to certain conditions, including approval of the Silver Run stockholders. Later that day, Riverstone informed the independent board members of Silver Run, William D. Gutermuth, Jeffrey Tepper and Diana Walters

(the "Silver Run independent directors") of the transaction to acquire CRP and its potential assignment to Silver Run and scheduled a board meeting to be held on July 14, 2016 to discuss the matter.

On July 12, 2016, Riverstone sent materials prepared for the July 14, 2016 Silver Run Board meeting to the independent directors.

On July 13, 2016, a meeting of the Limited Partner Advisory Committee ("LPAC") of Riverstone Fund VI was held telephonically to discuss the LPAC's approval to assign the fund's rights and obligations under the Contribution Agreement to Silver Run and purchase Class A Common Stock to help Silver Run finance the transaction. At the meeting, the LPAC members discussed the benefits of such assignment, including, among others, that investing in CRP indirectly through Silver Run would reduce Riverstone Fund VI's exposure to a more desirable level and enhance Riverstone Fund VI's liquidity as it would be invested in a public company. Additionally, CRP would benefit from Mr. Papa's involvement on a day-to-day basis going forward and enhanced access to capital markets to execute its growth plan. Also on July 13, 2016, following interviews of potential candidates conducted by the Silver Run independent directors, the Silver Run independent directors, selected Evercore Group L.L.C. ("Evercore") to render financial advisory services to the Silver Run Board in connection with Silver Run's potential acquisition of CRP.

On July 14, 2016, the Silver Run Board held a special telephonic meeting to discuss the proposed acquisition of CRP by Silver Run. This meeting was attended by Mr. Papa, Mr. Thomas Walker, Silver Run's Chief Financial Officer, Mr. Stephen Coats, Silver Run's corporate secretary, and the Silver Run independent directors. Representatives from each of Weil, Gotshal & Manges LLP ("Weil"), Silver Run's counsel, Riverstone and Latham also were present at the meeting. During that meeting, Mr. Papa and representatives of Riverstone, Latham and Weil described CRP, the transaction structure, the material provisions included in the Contribution Agreement, the investment rationale and the due diligence performed by Riverstone and its advisors on CRP.

Representatives of Citigroup Global Markets Inc. ("Citi"), which was retained by Riverstone as its exclusive financial advisor to assist Riverstone in its due diligence of CRP's acreage and reserves, then joined the meeting at Riverstone's request. In selecting Citi as its advisor, Riverstone considered, among other things, Citi's reputation and experience. The Citi and Riverstone representatives provided an overview of Citi's engagement with Riverstone and informed the Silver Run Board that any duties arising out of Citi's engagement with Riverstone were owed solely to Riverstone and, as such, Silver Run and the Silver Run Board could not and should not rely on work done by Citi or anything said by Citi at the meeting or otherwise, including the summary it was going to then provide to the Silver Run Board, at Riverstone's request, of the technical diligence performed by Citi pursuant to its engagement by Riverstone. Representatives from Citi then provided a summary of the technical diligence performed by Citi on CRP's acreage and reserves. The summary described the public, proprietary and CRP-provided sources of information Citi used in its evaluation of geology, petrophysics, reservoir engineering and completion engineering, and Citi's assessment of CRP's single well type curves and horizontal drilling inventory by both area and target zone. Citi's assessment was substantially similar to the assessments of both CRP's senior management and CRP's independent reserve auditor, Netherland, Sewell & Associates, Inc. Citi left the meeting immediately after providing such summary.

Evercore subsequently joined for a portion of the meeting to provide a status update to the Silver Run Board on its evaluation of the transaction. The Silver Run Board subsequently approved the retention of Evercore to render financial advisory services in connection with the proposed transaction and thereafter entered into an engagement letter dated July 20, 2016.

Thereafter, Mr. Papa and the representatives from Riverstone, Latham and Evercore left the meeting, and the Silver Run independent directors continued to discuss the proposed transaction with representatives from Weil. The representatives from Weil reviewed with the Silver Run independent

directors their fiduciary duties under Delaware law in connection with their evaluation of the proposed business combination. The representatives from Weil further discussed with the Silver Run independent directors certain possible provisions that could be proposed by the Silver Run independent directors designed to protect the public stockholders from certain potential actions of Riverstone as the majority stockholder of Silver Run, following the consummation of the transaction (which provisions are described in the second succeeding paragraph below). Following this discussion, the Silver Run independent directors directed the representatives from Weil to contact Latham to discuss implementing such provisions in the documentation for the business combination.

Also on July 14, 2016, Mr. Papa and representatives of Riverstone held an introductory meeting with representatives of certain funds regarding the possibility of investing in Class A Common Stock of Silver Run as part of a $200,000,000 private placement. The private placement was intended to increase CRP's liquidity by placing an additional $100,000,000 of cash on the balance sheet, reducing the overall size of the investment by the funds controlled by Riverstone to a more desirable level and increasing the public float after closing.

Later that day, subsequent to the Silver Run Board meeting, a representative of Weil contacted by telephone a representative of Latham to discuss the transaction. During this conversation, as directed by the Silver Run independent directors, the Weil representative stated that Silver Run's independent directors were cognizant that the equity financing would result in Riverstone and its affiliates owning slightly in excess of 50% of the outstanding voting securities of Silver Run and, in connection therewith, the Silver Run independent directors thought it appropriate for Riverstone to agree to refrain from taking certain actions while it holds its controlling interest. Specifically, Weil requested that, among other things, Riverstone agree (a) not to agree to a sale of Silver Run that would involve the Riverstone entities receiving greater per share consideration than the consideration received by Silver Run's public stockholders and (b) that any future "take private" transaction of Silver Run by Riverstone would be subject to the approval of a majority of the disinterested directors of the Silver Run Board and a majority of the public stockholders of Silver Run. The Latham representative informed the Weil representative that he would pass along the request to Riverstone and respond in due course.

On July 15, 2016, LPAC granted approval to NewCo to assign its rights and obligations under the Contribution Agreement to Silver Run as presented.

On July 16, 2016, a representative from Latham sent an email communication to Weil with regard to the status of open issues in the connection with the transaction. In the email, the Latham representative stated that Riverstone was not willing to agree to the minority stockholder protections requested by the Silver Run independent directors and relayed by Weil on July 14, 2016. On July 19, 2016, Latham sent a draft of the Agreement to Assign to representatives of Weil that did not include the minority stockholder protections discussed between Weil and Latham on July 14, 2016.

On July 18, 2016, Mr. Papa and representatives of Riverstone held an introductory meeting with representatives of certain funds regarding the possibility of investing in Class A Common Stock of Silver Run as part of a $200,000,000 private placement.

On July 19, 2016, representatives from Evercore held a telephonic meeting with the Silver Run independent directors and with representatives of Weil in attendance to review Evercore's preliminary valuation analysis.

Later in the day on July 19, 2016, the Silver Run independent directors held a conference call with representatives of Weil. Representatives from Weil reported Riverstone's position in connection with the requested minority stockholder protections. Following a discussion, the Silver Run independent directors directed Weil to include the minority stockholder protections discussed at the meeting in its written comments to the Agreement to Assign.

On July 20, 2016, Weil sent a revised draft of the Agreement to Assign to representatives of Latham. The draft included a covenant of Riverstone that would prohibit Riverstone, without the approval of a majority of Silver Run's disinterested directors, from transferring voting securities of Silver Run to any person if, as a result of such transfer, such person would beneficially own more than 35% of Silver Run's voting securities unless such person agreed to commence a tender offer to acquire all of the outstanding shares of Silver Run at a cash price per share not less than the highest amount received by Riverstone or its affiliates. In addition, the draft Agreement to Assign included a standstill provision prohibiting Riverstone from, without the approval of the majority of Silver Run's disinterested directors, acquiring additional shares of Silver Run's voting securities following the completion of the Transactions, as well as a limitation on Riverstone's ability to enter into or support a future change of control transaction in which Riverstone would receive per share consideration in excess of that to be received by other stockholders. The draft Agreement to Assign also contained a covenant that so long as NewCo and certain of its affiliates held 5% of Silver Run's voting securities, NewCo and such affiliates would not change Silver Run's related person transaction policy currently in place that places restrictions on directors', officers' and 5% holders' transactions with Silver Run.

Between July 20, 2016 and July 21, 2016, representatives of Latham, Weil, the Silver Run Board and Riverstone discussed Weil's markup of the Agreement to Assign. Mr. Papa did not participate in the discussions.

On July 21, 2016, representatives of Latham delivered to representatives of Weil a revised draft of the Agreement to Assign which, among other things, removed the minority stockholder protection provisions other than the restriction on changing Silver Run's related person transaction policy.

Later that day, the Silver Run Board held a telephonic meeting, with representatives from Riverstone, Latham and Weil and Mr. Papa present for a portion of the meeting. Prior to the meeting, the directors were provided with materials relating to their review of the proposed transaction, including drafts of the transaction documents and a presentation from representatives of Evercore with respect to its financial analysis of the business combination. Mr. Papa and representatives from Riverstone described the background to the transaction, provided a report on the activities that had been conducted on behalf of Silver Run to identify an attractive business combination transaction, including the other business combination candidates that had been considered on behalf of Silver Run, and the negotiations between CRP and Riverstone. Mr. Papa also provided to the Silver Run Board an update on the business plan for personnel following the consummation of the business combination and the need to put in place a long-term incentive plan that is consistent with market terms in order to retain appropriate management personnel at CRP and Silver Run. After making this presentation, Mr. Papa and the representatives from Riverstone and Latham left the meeting.

At this point, Evercore joined the meeting. Evercore rendered its oral opinion to the Silver Run Board, subsequently confirmed in writing by delivery of a written opinion dated as of July 21, 2016 (the "Opinion"), to the effect that as of the date of the opinion and based upon and subject to the factors and assumptions set forth therein, the Consideration (as defined in the Opinion) to be paid by Silver Run in the Transaction (as defined in the Opinion) is fair, from a financial point of view, to Silver Run. The full text of the written opinion of Evercore, which sets forth the assumptions made, procedures followed, matters considered and limitations on the review undertaken in connection with the opinion, is attached to this proxy statement as *Annex G*. The meeting was adjourned at this point.

Later in the day, a meeting of the Silver Run Board was reconvened. Mr. Papa did not participate because of his relationship with Riverstone. Representatives from Riverstone, Latham, Weil and the Silver Run Board then discussed the deletion of the minority stockholder protections from the draft Agreement to Assign. Representatives from Riverstone expressed, among other things, their view that the proposed business combination was a unique opportunity that would not be possible for Silver Run without Riverstone's participation and commitment, that Riverstone had already invested significant

resources to enter into the Contribution Agreement and is contractually responsible to effect the business combination notwithstanding the assignment to Silver Run, that Riverstone is increasing its equity stake in Silver Run as part of the equity financing for the transaction rather than as a means to obtain control of Silver Run, the public stockholders will be voting on the business combination and will also have the ability to have Silver Run redeem their shares if they wish to do so and that an agreement to restrict Riverstone's or its various funds' ability to transfer and acquire Silver Run voting securities would be inconsistent with such funds' fiduciary duties to their respective limited partners. Riverstone reiterated that other than the restriction on changing Silver Run's related person transaction policy, it would not agree to any minority stockholder protections in the Agreement to Assign. At this point, the representatives from Riverstone and Latham left the meeting.

The Silver Run independent directors then discussed Riverstone's final refusal to agree to the requested minority stockholder protections and their view that, notwithstanding the absence of those provisions in the definitive documentation with CRP, the transaction was a unique opportunity and, given the lack of attractive and actionable alternative opportunities Mr. Papa and Riverstone had identified and evaluated to date, represented the best business combination transaction reasonably available to Silver Run. Accordingly, the Silver Run independent directors (i) determined that the terms of the Agreement to Assign, the Contribution Agreement and the other transactions contemplated thereby are in the best interests of Silver Run stockholders, (ii) approved and declared advisable the Agreement to Assign, the Contribution Agreement and the transactions contemplated thereby, (iii) directed that the Agreement to Assign, the Contribution Agreement and the transactions contemplated thereby be submitted to Silver Run stockholders for adoption, and (iv) recommended that Silver Run stockholders vote in favor of adoption of the Agreement to Assign, the Contribution Agreement and the transactions contemplated thereby.

Also on July 21, 2016, certain funds agreed to purchase $200 million of Class A Common Stock from Silver Run at $10.00 per share. In conjunction with this private placement, the funds controlled by Riverstone agreed to be ready, willing and able to purchase an equivalent number of additional shares of Class A Common Stock at $10.00 per share in the event any existing public stockholders elected to redeem their shares upon stockholder approval of the CRP acquisition.

Later in the evening of July 21, 2016, Silver Run and NewCo executed the Agreement to Assign. Silver Run then issued a press release before the opening of the financial markets in New York City on July 22, 2016 announcing the execution of the Agreement to Assign.

On August 19, 2016, a limited partner and LPAC member of Riverstone Fund VI spoke with representatives of Riverstone Fund VI to express its view that the LPAC members had not been provided with adequate information to support a valid consent on July 15, 2016 to NewCo's assignment of its rights and obligations under the Contribution Agreement to Silver Run. On that call, representatives of Riverstone Fund VI expressed their disagreement with that characterization. Counsel to the LPAC member sent a letter to Riverstone Fund VI on August 22, 2016 outlining the LPAC member's views. Specifically, the letter stated the LPAC member's belief that Riverstone Fund VI's general partner failed to disclose the benefit derived by certain principals of Riverstone Fund VI's general partner and its affiliates related to the Sponsor's ownership of founder shares and private placement warrants, which interests it believed would have a dilutive effect on Riverstone Fund VI's interests and would represent a diversion of a portion of the investment opportunity with respect to the transaction from Riverstone Fund VI.

On August 25, 2016, representatives of Riverstone Fund VI and the LPAC member had a follow-up telephone conversation wherein representatives of Riverstone Fund VI again expressed their belief that the LPAC members had received all of the material information necessary to support a valid consent. Thereafter, through August 31, 2016, representatives of Riverstone Fund VI had numerous telephone conversations with the other LPAC members to review the information previously provided

PX 292

From: "Tekkora, Baran" <btekkora@riverstonellc.com>
Sent: Sat, 26 Aug 2017 20:55:19 +0000 (UTC)
To: "Hackett, Jim" <JHackett@riverstonellc.com>
Cc: "Lancaster, John" <jlancaster@riverstonellc.com>; "Jessup, John"<JJessup@riverstonellc.com>
Subject: Preliminary Valuation
Attachments: Preliminary Blue Mountain Model.pdf;ATT00001.htm

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Jim,

We wanted to come back to you with our thoughts on valuation of the Linn Midstream assets. Below is the detail and the model from John Jessup who has done a great job coming up to speed on the asset.

Based on the work we have done with the Rock team, we believe a theoretical valuation range is $500-700m. If the upstream development and volumes play out as assumed, we can see a midstream entity paying within that range. That's not necessarily what we as Riverstone is prepared to pay today, mainly because there are several risks that could materially impact valuation. Some of those are - only one customer (Roan) and no third party customers, Roan's access to capital, and the uncertainties in the gathering contract. When you boil it down, we would be purchasing the contract with Roan as there are not many assets. Because of these reasons, we are closer to $300m subject to more due diligence. Our thoughts on valuation and willingness to own the business will increase if we as Riverstone have a stake in both the upstream and midstream (similar to AM/KFM) where we have a say in the upstream development pace and hence midstream volumes.

We had a conversation with Lancaster and gave him more color. Happy to get on the phone with you as well. I am currently 7 hours ahead of east coast time. I'll leave it to you and Lancaster to figure out the tactics and next steps with the other side. After that, we would be happy to dig in more.

One last point about the process. It sounds like Jefferies reached out to a handful of potential buyers and shared information with them. Not sure yet who they are or how serious.

Let us know if you have any questions.

Baran Tekkora
Riverstone Holdings
[redacted]

Begin forwarded message:

From: "Jessup, John" <JJessup@riverstonellc.com>
Date: August 26, 2017 at 2:22:04 AM GMT+3
To: "Lancaster, John" <jlancaster@riverstonellc.com>
Cc: "Tekkora, Baran" <btekkora@riverstonellc.com>
Subject: Preliminary Blue Mountain valuation

John,

Attached is a financial summary that lays out the estimates we currently have for Blue Mountain midstream. I've listed below the key assumptions and sources in this analysis. We have limited

information from Jefferies/Linn at this time and our work would benefit significantly from another round of data exchange with them. To respond to the request for a valuation range, I'd say the math attached/below suggests $500-700 million. That math is informed by limited information on a brand new business and needs to be taken with a grain of salt. The Rock guys perhaps said it the best, Linn has a contract more so than a business at this point.

The attached file runs Rock's base case Roan volumes and uses a methodology described below to direct certain of those volumes to Blue Mountain. Given Blue Mountain's early stage, the model assumes no upfront leverage but access to $50mm of construction financing (~50% of unlevered FCF deficit through YE 2018) to be used during the initial build out of the system. The model then assumes a 2022 exit at 9x trailing EBITDA. Under those assumptions, a $500 million purchase price generates 29%/3.5x and a $700 million purchase price generates 22%/2.7x.

Triangulating those results against multiples, the low end of the value range implies 9.0x 2018E and 5.0x 2019E EBITDA and the high end of the range equates to 12.6x 2018E and 7.0x 2019E. By comparison, Eagle Claw transacted at 17.4x FY1 and 8.0x FY2, Silver Run's purchase of KFM was at 7.3x 2018E and 4.2x 2019E, and other recent comps (Navigator, Alpha Crude Connector, Outrigger, SXL/Vitol Midland Crude) averaged 19x FY1 and 14x FY2. Trading comps (AM, CNNX, EQM, HESM, NBLX, RMP, WES) average 12.5x 2018E, including GP value in MLP EV. Comparing all these high-growth companies on forward multiples obviously begs the question of what forecasts are being used and the capital intensity to achieve those projections. Blue Mountain is also even earlier stage than many of the transaction comps and currently has only one customer. But based on the comp information we have, a value range of $500-700 million lines up fairly well to market, with some discount.

The Rock team was very helpful in pulling this forecast together. However, I would caution that we shouldn't call this a "Rock case" or refer to "Rock assumptions" – we started with high-level Rock volumes and worked on the methodology together but there are a number of items that generated debate and we tried to land on a balanced approach based on limited information. We also jointly identified several places where we have insufficient information from Linn/Jefferies. I also have not discussed the financial and valuation results of the current model with the Rock team – they do not know the range indicated above.

Key assumptions / methodology / sources:

Volume

- Volumes in the model are based on Rock estimates used for their Roan upstream valuation work
  - Excluded any third party customer volumes as upside
- Rock assumes the vast majority of Roan development will occur in the merge AMI covered by the Blue Mountain (and Enlink) contracts
  - We therefore included all Rock development volumes in this forecast (may overstate ultimate volumes, especially in early periods)
- We then removed Roan non-op volumes from the forecast, assuming Roan/Linn will not be able to direct those to Blue Mountain (may understate ultimate volumes)
- Of the operated volumes, we assumed 50% were operated due to legacy Linn WI levels and 50% were operated due to legacy Citizens WI levels and then further assumed Blue Mountain would receive the 50% of volumes operated due to legacy Linn WI levels
- Finally, for those operated volumes that were operated due to legacy Linn WI levels, we assumed both non-op and royalty volumes would come with Roan WI volumes
  - Long story short, we took Rock's projections, then took only operated volumes, then divided in half, then gross up to capture associated 3rd party non-op and royalty volumes
  - This also makes the assumption that all operated development would be within a reasonable catchment area near Blue Mountain infrastructure over time, which we

believe is a fair assessment due to the "blockiness" of Roan's operated acreage in the merge county line area

- We took at face value the Linn/Jefferies btu factor, which seems high for the NGL yield produced by PHD Win (may overstate certain revenue items)

Costs

- Did not change the Jefferies opex assumption other than to include an inflation escalator – pulled some asset-level comps but the data is difficult to compare on a $/mcf basis across very different assets; but their asset-level EBITDA margins are not unreasonable for a new system
- Added G&A equal to 10% of revenue – in-line with Eagle Claw / KFM memos

Commodity prices / revenue streams

- $50 / $3 flat and 40% NGL barrel to WTI at the tailgate
- Used the Jefferies model as the basis for our revenue build, including their calculation of the various fee, shrink, and POP revenue streams. I tried to audit these against the contract we have but my ability to fully do so was impeded by not having full information about things like shrink, ethane rejection/recovery assumed, etc
  - In the event the Jefferies model has a calculation error on one of the fee streams, it carried through to our calculations

Capex

- Used Jefferies / Linn cryo plant capex but moved timing of second plant slightly to fit revised volumes
- Altered gathering capex profile to fit revised volumes assuming $250k per "legacy Linn" operated well added; given overlap with the Enlink contract, which midstream company lays to what Roan operated well will be negotiated and complicated – this is a simplifying assumption
- Added maintenance capex equal to $0.025 per mcf

I'm available to discuss at your convenience.

Thanks,
John

John M. Jessup
Riverstone Holdings LLC
[redacted]